Petroleum Research 11 (2026) 848–869

Contents lists available at ScienceDirect

Petroleum Research

journal homepage: http://www.keaipublishing.com/en/journals/petroleum-research/

Review Article

A technical review of in situ conversion technologies for oil shale

Atif Zafar *, Mishal Iqbal, Yumna Sami

Department of Petroleum Technology, University of Karachi, Main University Road, Karachi, 75270, Pakistan

ARTICLE INFO

Article history:
Received 1 August 2025
Received in revised form
20 January 2026
Accepted 21 January 2026
Available online 29 January 2026

Keywords:
In situ conversion technologies
Injection technologies
Kerogen pyrolysis
Oil shale
Pores and fractures
Terahertz spectroscopy

ABSTRACT

The global depletion of conventional oil and gas resources has led to the exploration of alternative energy resources. Among these resources, oil shale is a fine-grained sedimentary rock with a large amount of kerogen that has attracted increasing attention from the hydrocarbon industry and researchers due to the enormous global reserves of oil shale, which are larger than those of conventional crude oil. However, *in situ* conversion technologies (ICTs) constitute a practical and environmentally friendly technology for extracting hydrocarbons from oil shale formations without traditional surface mining. This study provides a comprehensive analysis of the primary ICTs developed and evaluated in this field to date. Convection-based approaches, such as steam injections and modified thermal injection (MTI), conduction-based heating approaches, such as Shell's *in situ* conversion process (ICP) and ExxonMobil's Electrofrac™, and radiant heating techniques that utilize radio frequency and microwave energy, are critically evaluated in this study. Advanced innovations, such as near-critical water extraction, nitrogen-assisted *in situ* conversion process (NAICP), and terahertz spectroscopy (a diagnostic tool for reservoir evaluation), highlight the advanced direction of this field. Mechanistic insights into pore–fracture network formation, kerogen pyrolysis, and their function in improving permeability and hydrocarbon flow have also been analyzed. Challenges related to energy efficiency, operating costs, and environmental impacts still remain despite these technological advancements. Addressing these limitations by maximizing thermal delivery, catalytic enhancement, and integrated modeling will be crucial for realizing the large-scale viability of ICTs. Future research should focus on increasing the efficiency of energy recovery while maintaining environmental sustainability and economic competitiveness.

© 2026 Chinese Petroleum Society. Publishing services by Elsevier B.V. on behalf of KeAi Communications Co. Ltd. This is an open access article under the CC BY-NC-ND license (http://creativecommons.org/licenses/by-nc-nd/4.0/).

1. Introduction

Developing a wide variety of suitable alternatives for increasingly exhausted oil and gas resources is a key strategic challenge for the national energy system. Vast reserves of oil shale exist around the globe. These reserves can be converted into 400 billion tons of oil shale, which is equivalent to 5.4 times the world's entire demonstrated reserves of oil (Wang and Li, 2019). Low-temperature distillation can be used to create oil shale, a solid organic sedimentary rock that is combustible, has a calorific value of more than 4.2 MJ per kilogram, and has substantial amounts of oil and ash greater than 3.5% of oil shale's total volume. Furthermore, oil shale is classified as an unconventional oil and gas resource (Hou et al., 2022; Hu et al., 2022).

When oil shale undergoes thermal conversion, the resulting hydrocarbons can be formally categorized into shale oil, heavy oil, light oil, and natural gas. The largest reserve of oil shale is found in the United States, which contains about 76.89% of the world's potentially recoverable shale oil resources (Dyni, 2003). China has significant amount of oil shale resources, with a total of approximately 719.9369 billion tons, of which about 47.6439 billion tons can be converted into oil (Liu et al., 2017). This oil shale is a key resource for China's energy needs, making it highly valuable. Currently, one of the most important sources of energy for the future is oil shale (Al Rassas et al., 2020a; Aurela et al., 2021; Kalu et al., 2022). Oil shale deposits can be found in more than 42 countries worldwide in geological formations originating from the Cambrian period to the Eocene period. These sediments are collectively more than seven times larger than the world's recoverable crude oil reserves, which are approximately 170 billion tons (Wright et al., 2013). China has the second-largest reserve of oil shale in the world (Liu et al., 2003). Therefore, Chinese groups and

* Corresponding author.
E-mail address: atif.zafar@uok.edu.pk (A. Zafar).
Peer review under the responsibility of Editorial Office of Petroleum Research.

https://doi.org/10.1016/j.ptlrs.2026.01.013
2096-2495/© 2026 Chinese Petroleum Society. Publishing services by Elsevier B.V. on behalf of KeAi Communications Co. Ltd. This is an open access article under the CC BY-NC-ND license (http://creativecommons.org/licenses/by-nc-nd/4.0/).

international organizations are working to find better ways to use and process oil shale more quickly and efficiently. These efforts primarily focus on three areas: (1) the two primary components of technology for horizontal well guiding drilling, which are precision ranging, drilling, and rotary guidance; (2) the primary components of heating technology—high-efficiency, composite heating, catalytic enhancement, and downhole heaters; and (3) the three primary elements of composite reservoir alteration technology—gas drive water sealing, CO_2 dry fracturing, and acid fracturing (Wang et al., 2024). Two main types of oil shale *in situ* retorting technologies exist: aboveground and underground retorting (Crawford et al., 2008; Wang et al., 2012). The construction of large installations and systems on the surface, a component of surface retorting technology, provides an aerobic, high-temperature environment (Yasir et al., 2020a). Shale oil and gases are produced by retorting underground oil shale after being crushed to a certain size and transferred to a surface-retorting apparatus (Kang et al., 2020a; Zafar et al., 2020a). Underground retorting, which can be categorized into *in situ* retorting, mechanical crushing, and real in-ground retorting, eliminates the need for surface processing (Li et al., 2015; Persoff, 1980).

This study provides a comprehensive overview of current advancements and methodologies in oil shale *in situ* conversion technologies. It also summarizes the suitability of various heating techniques and pyrolysis catalysts and offers ideas and viewpoints on the use of *in situ* technologies in oil shale applications, focusing on technologies such as terahertz spectroscopy, reservoir fracturing, related injections, oil shale catalysis, and efficient heating.

2. Key properties of oil shale

Immature kerogen, which cannot be directly recovered, constitutes most of the solid material found in organic shale. Shale must be heated to release oil. This is accomplished through a process called low-temperature dry distillation (Yörük et al., 2020). During this process, shale is heated to temperatures between 450 °C and 500 °C. Pyrolysis, which includes both *in situ* and ex situ methods, is the most widely used method for extracting oil from oil shale (He et al., 2022).

Ex situ methods for processing oil shales include the pyrolysis method, screening, and grinding. The most common processing technology is shallow deposit mining, which offers low costs and increased design safety. Ex situ mining technology has only been designed for open-field applications and has resulted in significant environmental degradation (Hu et al., 2022). Underground oil shale reservoirs are heated artificially as part of the *in situ* conversion mining process. This process breaks down the solid kerogen within the shale, which is then extracted using specific procedures. This technology extracts resources for deep oil at low costs, which allows the technique to keep pace with trends in oil-shale processing (Kang et al., 2022). Despite being considered efficient and environmentally beneficial, *in situ* oil shale extraction has been related to high energy consumption (Wang et al., 2024). By modifying the energy required for chemical reactions and managing the reaction process, catalysts can lower the high level of energy used in oil shale *in situ* conversion. In this process, oil and gas are extracted from the formation by injecting catalysts into the reservoir to allow for pyrolysis and a complete interaction with the oil shale within the reservoir's pressure and temperature conditions (Sun et al., 2022; Wang et al., 2019a). Oil shale is a naturally dense, impermeable material with few natural fractures and little intrinsic porosity (Hou, 1984). Kerogen, or microscale organic debris, is frequently evenly distributed throughout shale (Qian et al., 2011). While slight differences in the mineralization conditions of the various metallic elements present in oil shale exist (Pan et al., 2016; Tao et al., 2013), oil shale deposits around the world generally share the same core characteristics. Typical traits of oil shale are listed in the subsections that follow.

2.1. Fine-grained matrix and organic matter properties

Most oil shale in China is composed of clay minerals based on kaolinite and mica, whereas most oil shale in Estonia, Russia, and the US is composed of carbonate minerals (Qian et al., 2011). Eseme et al. (2007) found granules of sand bigger than 60 μm and grains of muddy sand that ranged in size from 2 to 60 μm in the northern German Posidonia oil shale, and that most mineral particles were smaller than 2 μm. The kerogen organic matter in this oil shale is elongated, flat, usually less than 19.9 μm, and distributed nearly uniformly across the deposit's surface. Oil shale develops micro-sized pores and fractures because of the breakdown of organic kerogen during pyrolysis. These microstructures enable the released gas and oil to exit the ore and be settled outside the furnace in aboveground retorting systems. However, for the produced fluids to reach the production well in *in situ* retorting, they must pass through the same system of pores and fractures created by pyrolysis. The development of an effective microfracture system is crucial for the movement of hydrocarbons, regardless of whether the shale is crushed into smaller pieces for surface processing or remains intact underground. Ultimately, optimizing the retorting process in both techniques requires an understanding of the mechanisms governing the evolution and spatial distribution of pores and fractures (Kang et al., 2020a; Zafar et al., 2020b).

2.2. Stratified properties of oil shale

The layered or laminated structure of oil shale produces anisotropic mechanical and thermal properties that change depending on whether the direction is perpendicular to or aligned with the bedding planes (Wang et al., 2019b). The Fushun oil shale's hardness shows a directional dependence, with values of almost 35 perpendicular to the strata or bedding plane and 27.8 aligned to them, yielding a ratio of 1.24. Maoming oil shale exhibited a marginally larger discrepancy in contrast, with a hardness ratio of 1.43. The shear resistance of the Green River oil shale exhibits even more noticeable anisotropy, ranging from 6 MPa to 12 MPa along the bedding layers to a much higher range of 21.4 MPa–31.5 MPa perpendicular to them. This indicates a directional strength ratio of 2.94. These changes demonstrate how the layered structure affects the mechanical properties of oil shale (Qian et al., 2011). Additionally, the Green River oil shale has been found to have noticeable stratified features (Saif et al., 2017a; Wang et al., 2018a). Mehmani et al. (2016) found that the heat conductivity parallel to the bedding direction was about 1.49–1.99 times greater than that in the direction perpendicular to the bedding, whereas Nottenburg et al. (1978) characterized the heat-transfer behavior of Green River oil shale by experimentally determining its thermal conductivity over a wide range of temperatures and shale grades. Moreover, it has been found that the length of kerogen particles ranged from several microns to tens of microns, and was usually flattened as strips with a very definite layered feature (Eseme et al., 2006, 2007). Fig. 1 illustrates the layered and stratified structure of oil shale in the Kuh-e-Kaino section. Furthermore, the kerogen particles in the shale ranged in size from a few microns to tens of microns and usually took the form of flattened, strip-like structures, demonstrating the unique layered morphology of the material (Mehmani et al., 2016).

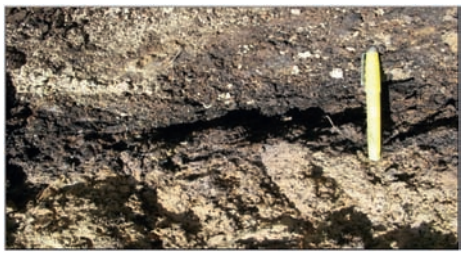


Fig. 1. Macroscopic characteristics of oil shale layers in the Kuh-e-Kaino section (Kang et al., 2020a).

3. Changes in oil shale during pyrolysis

3.1. Evolution of pores and fractures

Two key issues arise in both the *in situ* and ex situ retorting processes of oil shale: (1) In what ways does the internal temperature of oil shale increase to the pyrolysis temperature while undergoing outward high heat transfer? (2) How do gas and liquid crudes escape from shale formations? These questions have led to the development of new industrial processes. Oil shale ore is crushed into smaller particles and heated to extract hydrocarbons in the aboveground retorting process (Khalil, 2013). The Maoming retort furnace in China uses slightly larger ore blocks, between 14.9 mm and 75.2 mm in size, whereas the Fushun retort furnace uses blocks that range from 7.9 to 74.6 mm (Chen et al., 2010; Hou, 1984). Estonia's Kiviter furnace uses ore blocks that are 25–125 mm in size, whereas the furnace of Brazilian Petro Six uses 6–75 mm blocks (Qian et al., 2011). Shell initiated an *in situ* retorting technique using electrical heating based on the idea that many new pores and fissures form during the heating and pyrolysis of oil shale (Brandt, 2008). This method makes it easier to move gas and oil that has been pyrolyzed to the production well and eventually to the surface (Brandt, 2008; Kashif et al., 2019). Therefore, regardless of the type of retorting procedure used, the formation of pore spaces and fractures is the main concern related to the development of oil shale and how they evolve under different heating and pyrolysis conditions.

3.1.1. Properties of pyrolysis-based oil shale

Oil shales from Fushun, Maoming, Green River, and Estonia include trace amounts of metallic materials that enhance pyrolysis reactions during thermal decomposition and function as catalysts (Zheng et al., 2012). Korb et al. examined the organic structure and mineral pore surfaces of oil shale when water, oil, and gas were present using nuclear magnetic resonance (NMR) techniques (Korb et al., 2014). This analysis provides important information about shale wettability, which is important for *in situ* extraction techniques. After heating between 350 °C and 450 °C (Guo and Ruan, 1995; Zafar et al., 2022), the pyrolyzed organic compounds from Maoming oil shale were found to consist of 81 alkanes and alkenes, 221 aromatic compounds, and 272 non-hydrocarbon species. According to Shi et al. (2012), the pyrolysis of Yaojie oil shale at 550°C-700 °C in a Sanjiang furnace produces roughly 85% shale oil that is primarily composed of heavy hydrocarbons and diesel. Additionally, retorted oil shale at 500 °C in an open system develops larger clusters of larger aromatic compounds and a higher concentration of protonated aromatic groups than samples retorted at 360 °C in a closed system, according to NMR studies on kerogen and pyrolysis residues (Cao et al., 2013; Tahir et al., 2020a).

Furthermore, spectra from zones with light- and dark-colored areas within the oil shale samples were compared by Alstadt et al. (2012). Their findings indicate that while the darker areas had higher concentrations of mineral matter, including clay minerals, dolomite, calcite, and pyrite, the lighter regions were rich in kerogen. Typically, kerogen in oil shale experiences severe thermal breakdown as the temperature rises between 300 °C and 550 °C, releasing shale gas and oil. The released gaseous products include hydrogen, carbon monoxide, carbon dioxide, methane, ethane, ethylene, propylene, and propane. The main constituents of liquid hydrocarbons are aliphatic and aromatic compounds. Furthermore, it has been demonstrated that trace metals such as iron (Fe), copper (Cu), and sodium (Na) act as catalytic agents that greatly accelerate the pyrolysis process.

3.1.2. Changes in fissures and pore structures

Independent of the heating strategy employed, oil shale transitions through a thermal cracking phase when elevated from room temperature to its pyrolysis threshold, initiating its chemical breakdown (Kang et al., 2009, 2011). Wang et al. (2018b) and Dong et al. (2018) at Taiyuan University of Technology (TYUT) were among the first to carefully examine the breakdown of oil shale under heat, looking to better understand oil shale's intricate behavior through investigation and testing. By employing microcomputed tomography (micro-CT) to record a detailed view of the thermal cracking process, the formation, connection, and evolution can be tracked throughout the heating process. Kang et al. (2009, 2011) examined the process of thermal cracking and the behavior of Fushun oil shale as it is heated from 20 °C to 600 °C, utilizing microcomputed tomography (micro-CT) analysis. They also investigated the emergence, connectivity, and progression of thermal cracks.

The pyrolysis process, in which kerogen is broken down by chemical reactions to produce gas and oil, starts once the temperature in oil shale reaches a critical threshold. Many pore spaces and cracks are created in the shale structure because of this process, which opens channels that improve heat transfer and facilitate the injection of fluids that carry heat (Geng et al., 2017). The generated hydrocarbons can also be released efficiently owing to these newly created channels. This is the most active and important stage of oil shale pyrolysis, and it has spurred a great deal of targeted research in the field (Kang et al., 2020a; Zhang et al., 2022) once its significance became apparent.

To better understand the connection between fracture development and fluid flow, Kang et al. (2011) examined the effects of thermal cracking during the pyrolysis of Fushun oil shale on its permeability. Their analysis revealed a notable increase in crack formation between 300 °C and 400 °C, suggesting that this temperature range contained the thermal cracking threshold. However, the precise threshold temperature was not known because of the wide 100 °C intervals used in the testing (i.e., 200°C-500 °C). Permeability was also assessed under compressive conditions at smaller intervals of 50 °C from 100 °C to 500 °C. Permeability noticeably increased between 355 °C and 401 °C, as shown in Fig. 2, coinciding closely with the start of thermal fracturing and kerogen pyrolysis. Permeability was measured at only 0.00175 mD at 350 °C, but by 400 °C, it had risen to 0.013 mD, and at 450 °C, it had further increased up to 0.029 mD. Oil shale is almost sealed off at room temperature and becomes significantly more porous as the temperature increases. This allows thermal fluids to enter the formation more deeply, thereby improving *in situ* retorting and more successfully initiating the pyrolysis process inside the reservoir. Tests using steam pyrolysis also revealed that bedding cracks significantly developed during the process (Fig. 3).

The thermal induced changes in void networks and crack propagation in oil shale samples from Daqing and Yan'an were investigated using high-resolution XμCT imaging and mercury

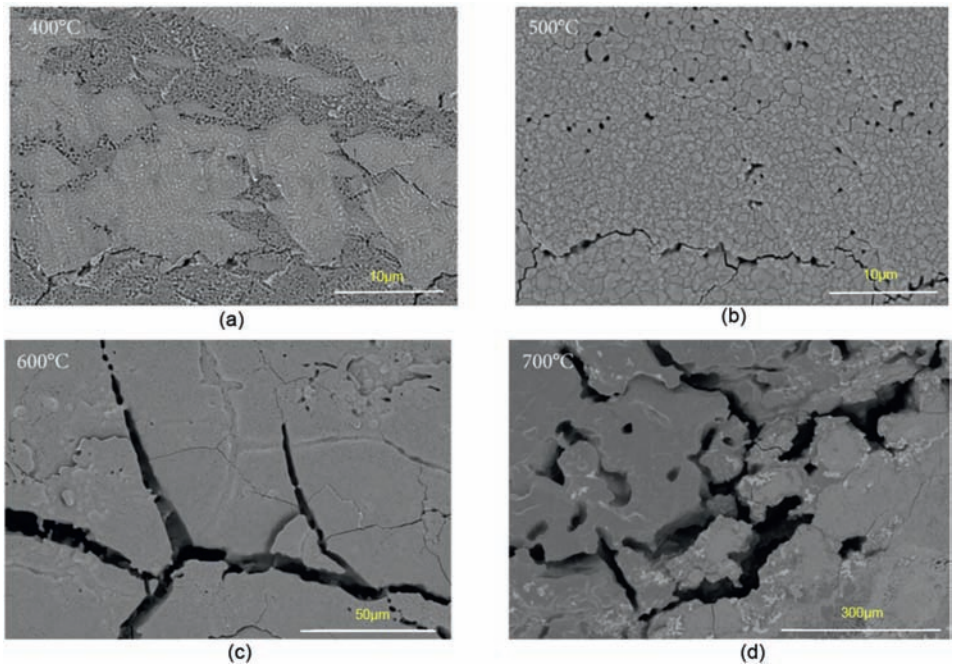


Fig. 2. Evolution of pores and microcracks in oil shale at different temperatures (Xi et al., 2023).



Fig. 3. Fushun oil shale cracking properties using water steam pyrolysis. The diameter of the pressure chamber is 300 mm, while the core's diameter is 70 mm (Kang et al., 2020a).

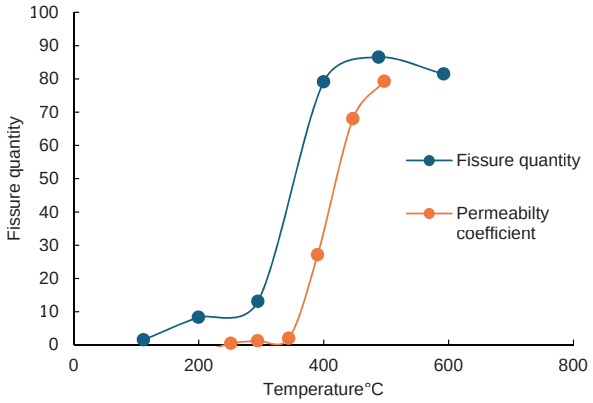


Fig. 4. A comparison of Fushun oil shale's permeability coefficients and fracture count with temperature (Kang et al., 2011).

injection capillary pressure analysis (Yang et al., 2016a; Zhao et al., 2012). It was found that the development of pores and fractures of oil shales changed rapidly with the rise in temperature from 200 °C to 400 °C in both Daqing and Yan'an. Ya'an shale had a pore volume of approximately 8% after pyrolysis, while Daqing shale had a pore volume of approximately 20%. Interestingly, the initial decomposition temperatures of both samples were lower than those reported for Fushun oil shale (Kang et al., 2009, 2011). The changes in the pore sizes and crack apertures of Fushun oil shale under increasing temperatures were investigated in a previous study (Geng et al., 2017), whose results showed that pyrolysis started between 300 °C and 400 °C (Fig. 4). However, the exact onset temperature could not be determined because of the 100 °C increments used during the tests. In another study, micro-computed tomography was used to track the changes in the morphology of pores and fractures (Fig. 5) as Green River oil shale broke down thermally (Saif et al., 2016), indicating that changes in porosity depend on temperature (Saif et al., 2017b). To analyze the pore and fracture characteristics over a temperature range of 380 °C–420 °C, measurements were made every 20 °C. The critical point of rapid structural change was marked by a notable increase in porosity between 389 °C and 401 °C. Porosity was insignificant below 389 °C but suddenly increased to between 22% and 25% within the 389°C-401 °C range. Significant variations in the distribution of porosity were also found in this study; zones with lower organic content displayed porosities of approximately 12%, while kerogen-rich areas displayed values as high as 38%.

Kang et al. (2017) investigated the effects of heating a small cylinder sample of oil shale ($\varphi = 0.82 \times 7$ mm) at varying temperatures on the changes in its small pore structures. They found a discernible increase in the overall porosity between 280 °C and 400 °C caused by a significant rise in both the number and average size of these pores. 3D modeling revealed that the largest pore clusters created thin snowflake-like shapes (Fig. 6). This made it easier for liquids to pass through the rock as these tiny pores expanded and joined to form wider channels. This method is particularly useful for introducing heat and allowing gas and oil to escape during pyrolysis.

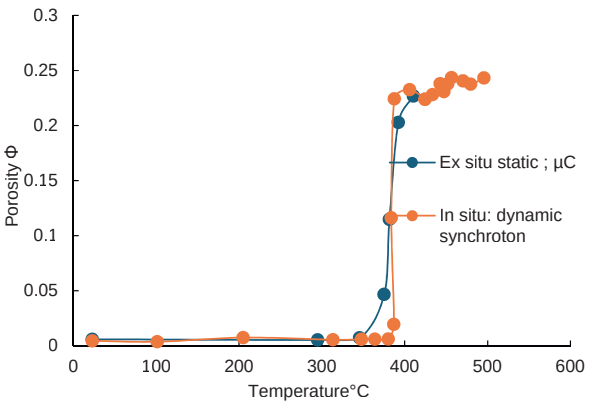


Fig. 5. Porosity in Green River oil shale as a function of pyrolysis temperature (Saif et al., 2016).

Tiwari et al. (2013) examined the changes in pore structures in oil shale both before and after thermal treatment with the use of X-ray micro-computed tomography (X-μCT). Their findings closely matched those of Kang et al. (2017). In a different study, Rabbani et al. created a fracture-opening correlation model after reviewing the experimental findings from (Saif et al., 2016). Their analysis identified a significant heterogeneity in their oil shale samples, with fluid flow along the bedding direction being three to five times higher than that along the perpendicular direction. The average permeability during pyrolysis was approximately 0.5 Darcy (Rabbani et al., 2017), which is approximately 100,000 times greater than the values found in the work of Kang et al. (2011) under confined triaxial conditions. This suggests that oil shales have noticeably increased permeability in the absence of mechanical stress.

Kibodeaux (2014) measured porosity and permeability during the *in situ* thermal conversion process (ICP), reporting values ranging from 25% to 33% and 1 to 10 millidarcies (mD), respectively. These values are an order of magnitude higher than those found under stress in the work of Kang et al. (2011). Meanwhile, Bai et al. (2017) determined that the critical decomposition temperature of Huadian oil shale is 350°C-400 °C. They found that porosity rose significantly to approximately 60% at 800 °C, while permeability ranged from 0.1 to 1.5 mD. The total disintegration of solid carbon materials, which causes pores and fractures to form quickly, is the cause of this notable increase (Gao et al., 2016).

Further information on permeability behavior, transport dynamics, and pore formation during pyrolysis is available in the studies of Burnham (2017) and Panahi et al. (2013). Nimblett and Ruppel (2003), for their part, investigated the evolution of permeability in mudstones, a type of rock that is closely related to oil shale. Theoretical approaches to evolving porous materials were first presented by Zhao (2004), Zhao et al. (2015a), and Zhao et al. (2015b). Later, a dual-network model that considers both pores and fractures in porous media was proposed (Zhao et al., 2016). These investigations provide the fundamental knowledge for describing the structural alterations in oil shale that occur during high-temperature treatment.

In sum, experimentally conducted studies on oil shale pyrolysis have shown that kerogen transformation and thermal breakdown cause the formation of extensive pore systems and fracture networks that range in size from micro-to macro-scale. By effectively transforming oil shale into a permeable, porous medium from a largely impermeable matrix, this structural evolution offers a strong theoretical underpinning and technical assistance for both surface retorting and *in situ* conversion procedures. The inherent low permeability of unprocessed oil shale, however, continues to raise concerns among researchers, with some contending that the dense structure of the material poses serious obstacles to the successful application of *in situ* technologies (Cha and McCarthy, 1982). However, when taken together, the findings of the reviewed studies indicate that pyrolysis facilitates the creation of interconnected networks of pores and fractures that allow hydrocarbons to flow.

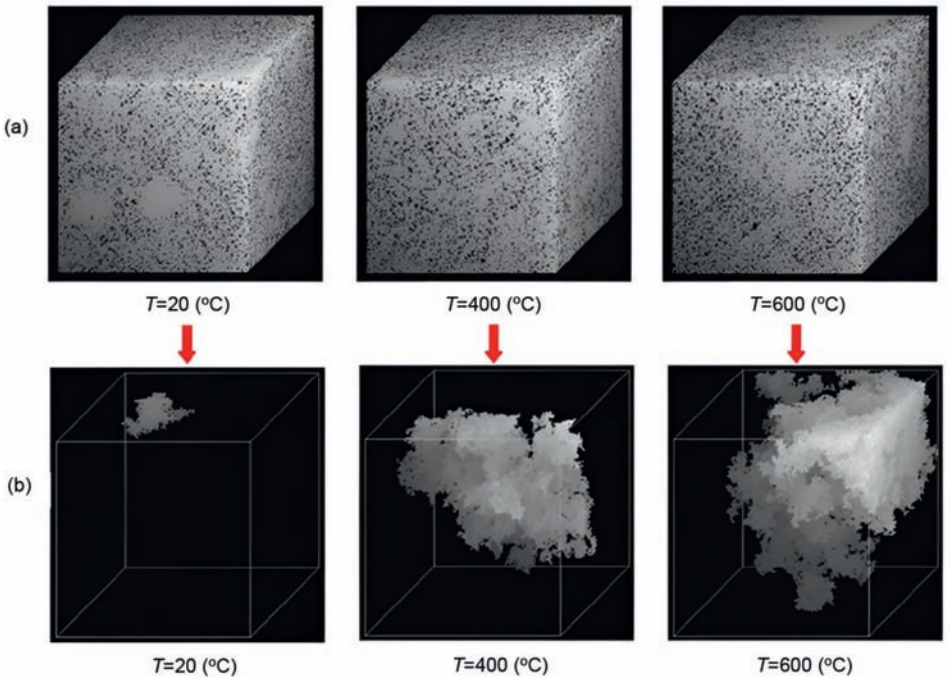


Fig. 6. 3D visualization of the largest 3D pore clusters at various temperatures (Kang et al., 2017).

3.2. Kerogen pyrolysis

Kerogen, the primary component of oil shale, must be separated from the shale using physical and chemical methods because it is strongly bound to inorganic minerals. Kerogen is an extremely complex organic polymer that is insoluble in organic solvents and possesses a molecular mass of several thousand Daltons on average. The kerogen conversion process creates fractured shale oil (Jagadisan and Heidari, 2022; Thana'Ani et al., 2022). Different techniques and heating methods for oil shale extraction have been suggested. All methods rely on the basic principle of thermal kerogen cracking, which is the process of shale oil production inside the oil shale (Zhang et al., 2020) that develops molecular structures of kerogen through nuclear magnetic resonance. These molecular structures are used to compute and evaluate by constructing 2D and 3D reactive sites and pyrolysis behavior models of kerogen; moreover, a three-stage theory of pyrolysis was introduced (Qing et al., 2022; You et al., 2019; Zhang et al., 2020). Chemical bonds such as those between carbon and oxygen, as well as carbon and sulfur, connect the carbon–carbon bridge, and heteroatoms such as nitrogen and sulfur inside aromatic structures are initially broken in the first stage. The first and second phases include breaking kerogen fragments and pyrolyzing them, which primarily entails the interchange of more stable hydrocarbons, such as hydrocarbons with long straight chains and cyclic chains, for aromatic structures. The cross-linking of free radicals and aromatic rings recombination makes up the majority of the third stage (Ma et al., 2022). Fig. 7 details the model of kerogen pyrolysis.

Zhao et al. (2022) found that during kerogen pyrolysis, the water molecules impacted by superheated steam injection may participate in chemical reactions. The breakdown of heavy shale oil and carbon, open-chain heterocyclic compound reactions, the interchange and transfer of OH radicals, and the creation of different products through interactions between fragments and free radicals are some examples of the reactions observed in more than 500 distinct kerogen model compounds in various settings (Zhang et al., 2020). The general structure in bond dissociation energy (BDE) values for important bond types is as follows: C–S < C–N ≈ C–O < C–C < C–H < C═C, even though the data show a wide range and some overlap. This pattern can be used to determine the kerogen pyrolysis order of bond cleavage. Therefore, BDE depends not only on the stability of fragments of free radicals but also on the chemical environment of the investigated bond. By looking at multiple bonds in the macromolecular model of kerogen, one can determine the order in which bonds break during kerogen pyrolysis. According to the three-phase kerogen pyrolysis theory, strength is the main factor influencing where chemical bonds break in the kerogen structure (Wang et al., 2024). The proposed first-order fractured chemical bonds have low bond dissociation energy (BDE) and predict the thermodynamic analysis of kerogen reaction activity. However, intricate free radical interactions are a part of the kerogen pyrolysis process itself. Bond energy alone is insufficient to identify the location of broken bonds (Lu et al., 2019). By assessing the kerogen molecular model's electronic properties, one can ascertain the properties of heterocyclic compounds, their orbital characteristics, and the electronic density distribution. This eases the kerogen pyrolysis process's chemical reaction.

3.3. Critical temperature and effective pyrolysis energy

Oil shale undergoes four endothermic modifications during the retorting process. The initial phase, known as the dehydration phase, occurs at 100 °C (Li and Yue, 2003; Zafar et al., 2020c). The heat from free water vaporization plus the heat from dry-basis heating add up to the heat capacity of oil shale, which is equal to the shale's inherent moisture content. The oil shale's heat capacity rises quickly as the free water vaporizes at around 100 °C. The second stage, the heat absorption stage, occurs between 100 °C and the first critical temperature Tci, where the organic matter that is included starts to pyrolyze. A linear relationship between reservoir temperature and heat capacity can be observed at this point. The third stage, sometimes referred to as the organic matter pyrolysis stage, starts at Tci and ends at the final critical temperature Tcf, marking the completion of the pyrolysis of enclosed organic matter. Pyrolysis induces both organic matter chemical reaction heat (ΔHc) and dry-basis endothermic energy (ΔHt) within this temperature range. According to Qing et al. (2009), Huadian oil shale has a pyrolysis activation energy of 240 kJ/mol; however, no studies on the alteration of ΔHc in Huadian oil shale have been published. Specifically, oil shale can only begin to pyrolyze when the heat carriers' temperature exceeds Tci, irrespective of the oil shale pyrolysis technology employed. The term "effective pyrolysis energy" (EPE) refers to the rise in heat carrier energy when the temperature surpasses Tci. In other words, shale oil cannot be produced by pyrolyzing the organic materials in oil shale with any energy below Tci. The fourth stage, referred to as the breakdown of the inorganic carbonates (Li and Yue, 2003), is the temperature range from the final stage of oil shale pyrolysis to higher temperatures. Several aboveground retorting methods assist in this process. The temperature must reach 900 °C for the inorganic carbonates to burn and release heat energy (Qing et al.,

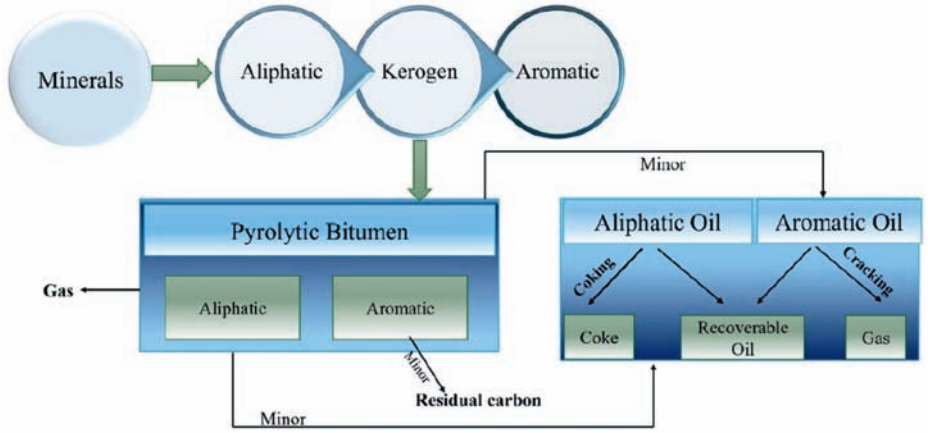


Fig. 7. Kerogen pyrolysis model (Wang et al., 2024).

2009). This step only generates energy, not shale oil. Kang et al. (2020a) studied the fluid heating pyrolysis energy consumption of Jimsar oil shale, and its total moisture content was 5%. Fig. 8 illustrates the energy usage of water steam-heated oil shale pyrolysis at different temperatures and various pressures, and the water and oil shale quality are set at 1.0 kg.

As Fig. 8 illustrates, the energy needed to pyrolyze and heat oil shale progressively rises with temperature. This is especially true during the organic matter pyrolysis stage, when Tci is 405 °C and Tcf is 500 °C, and at 100 °C when free water evaporation consumes a high amount of heat. Due to its enormous latent heat, oil shale requires much less energy to heat and pyrolyze at a given temperature than water steam. However, oil shale's organic materials cannot be pyrolyzed, and water vapor's energy delivery is useless as long as it is below Tcis. Energy consumption calculations were performed, starting at 400 °C (Kang et al., 2020a).

4. Distillation technologies for oil shale *in situ* conversion

Oil shale *in situ* mining technology involves hydraulic fracturing, in which fractured oil shale is heated using different techniques, including superheated steam injection, electricity combustion, and radiation (Al Rassas et al., 2020b; Liu, 2019). Shale oil and hydrocarbon gases are produced when the kerogen in oil shale undergoes pyrolysis at high temperatures (Kang et al., 2022; Xie et al., 2021). Table 1 summarizes the features of various *in situ* conversion oil shale technologies. Different technologies are used in oil shale reservoirs in China and other countries due to the different types of rock found in the shale resources of these reservoirs. The *in situ* conversion process (ICP) is generally used in oil shale technology in foreign countries; on the other hand, near-critical technology (NCW) is used. ICP technology is used to drill wells that produce heat in shale rock formations. The process uses electric heaters placed close together within the drilled wells. These heaters warm the shale to the temperature required to break it, allowing for effective oil and gas extraction (Xie et al., 2021). Downhole electric heaters are necessary for the ICP technology, which must be durable, able to withstand high temperatures, and compatible with the formation. The resulting oil content and oil shale thickness should not be less than the technical–economic lower limit. ICP technology can be applied to Chinese oil shale formations that are buried deep, have low thickness, and are of low-oil grade. An example of this is the scenario of short (dry) horizontal well technology (Hou et al., 2022). China is currently working on developing technology to extract oil from shale. For instance, the NCW developed by Jilin University has shown a desirable *in situ* conversion effect (Kang et al., 2022). The near-critical method employs a downhole heating system to raise the temperature of water injection to a near-critical temperature (around 380 °C). The NCW then acts as a medium to transfer, permeate, and cause the oil shale formation to swell while fracturing the kerogen of oil shale. This process facilitates the extraction of oil and gas from oil shale. NCW's advantages include strong heat transfer capabilities, less harm to the environment, and high activity (Wang et al., 2024).

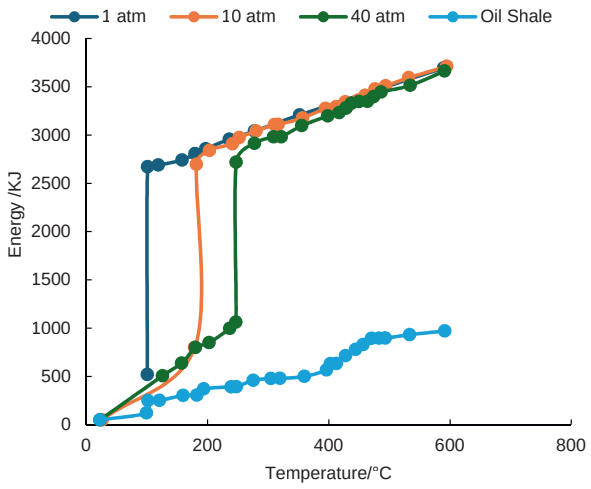


Fig. 8. Energy requirements for using steam to heat and decompose oil shale at various levels of steam pressure (Kang et al., 2020a).

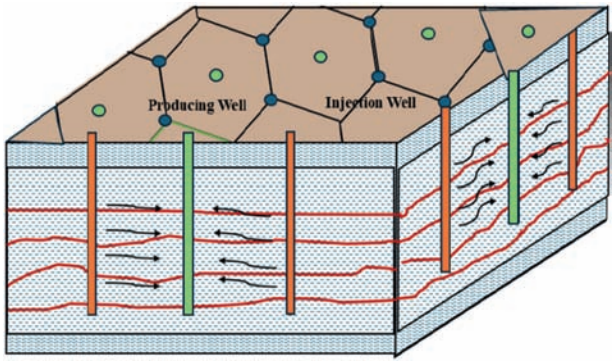


Fig. 9. Visual representation of Shell's ICP. The black wavy arrows indicate the flow direction of oil and gas. The red horizontal lines indicate the flow channels of oil and gas (Chen et al., 2024).

Four main types of *in situ* oil shale conversion that have been studied thus far are discussed as follows; these types are classified according to the mode of heat application. The first is conduction (e.g., Shell's ICP or ExxonMobil's Electrofrac™), in which heat moves very slowly through direct touch. The second type is based on convection and uses flowing fluids, such as superheated steam or air, to more efficiently transfer heat (e.g., AMSO's method, MTI's steam injection used in Chevron's Crush, Taiyuan University of Technology, and Petro Probe superheated air). The third variety employs radiant heating or *in situ* combustion, such as Raytheon's RF process, which heats the shale with energy waves to release its potential, and microwave technology. The fourth type is combustion heating technology, such as Topochemical Synthesis-Air (TSA) and True *in situ* (TIS) (Crawford and Killen, 2010). Additionally, emerging methods such as nitrogen injection, near-critical water, and terahertz spectroscopy are being explored (Kang et al., 2020a).

4.1. Conduction retorting technology

Electric heating *in situ* conversion involves the use of conductive proppants to fill and form an electric heater. These electrically conductive proppants are used to heat transfer onto the oil shale through heating wells, causing kerogen to convert into shale oil and flammable gas, which are extracted from production wells (Lee et al., 2017). Shell first proposed an *in situ* electric heating system for oil shale conversion in the 1970s. Shell has since applied for patents for its ICP in several countries (Prats et al., 1977). Shell's technique consists of drilling wells, placing electric heaters, and heating the shale to 600°C-700 °C, triggering pyrolysis and the thermal cracking of kerogen to expel oil and gas (Fig. 9). Such heating deforms the shale's structure, creating pores and fractures that facilitate hydrocarbon migration (Kang et al., 2020a). Shell ICP employs closely spaced vertical wells in patterned arrangements

Table 1
Overview of *in situ* conversion technologies of oil shale.

Heating Method	Technology/Process	Developer	Advantage	Disadvantage	End Status	Reference
Heat of reaction	Heating via *in situ* combustion	United States Bureau of Mines	Enhances energy efficiency and enhances heating speed	High operational costs and complex process control	Pilot Plan	(Burwell et al., 1973; Bai, 2015a)
	TSA technology	Jilin University			Pilot Plan	
	TIS	LETC			Lab	
	MIS	LLNL			Lab	
Conduction	ICP	Shell	High flexibility; straightforward management	Slow heat transfer and long heating	Demonstration	(Jagodzińska et al., 2021; Kang et al., 2020a; Symington et al., 2010; Yang et al., 2014)
	Electrofrac™	ExxonMobil			Pilot Plan	
	GFC	IEP			Lab	
	HVF	Jilin University			Lab	
Convection	CRUSH	Chevron	High heating efficiency; facilitates the production of oil and gas products; allows for the recycling of fracturing gas	Must separate the significant heat loss and the generated gas during the conveying process	Abandon	(Wang et al., 2013; Fang and He, 2009; Kang et al., 2020a; Sun et al., 2021; Chen et al., 2024)
	CCR	American Shale Oil			Abandon	
	IIST-VTPC	AsiaA.D.C.			Lab	
	Superheated air	PetroProbe			Lab	
	IVE	Mountain West Energy			Pilot plan	
	MTI	Taiyuan University of Technology			Pilot plan	
	SCW	Jilin University			Lab	
Radiant	Radio wave	Lawrence Livermore	High energy consumption when selecting the heating area	Radiated energy of technology: limited and immature transmission range	Lab	(Chen et al., 2024; Wang et al., 2013, 2024)
	RF/CF	Schlumberger			Lab	
	EOR	IITRI			Lab	
	Microwave	Phoenix Wyoming, Inc.			Pilot	

and has evolved to incorporate horizontal wells and advanced electric heating technologies to improve low-temperature pyrolysis (Kaminsky and Symington, 2008; Prats et al., 1977). Le Doan et al. (2013) performed a pyrolysis analysis of Green River oil shale in partially open conditions and obtained equivalent findings with Shell ICP: high-quality shale oil can be produced over time under low temperatures and proper pressure conditions (Zafar et al., 2020d).

Other conduction heat technologies include ExxonMobil's Electrofrac™, which forms electrically conducting fractures through a proppant-like material, allowing for resistive heating for *in situ* pyrolysis (Symington et al., 2010). Electricity is transmitted from one side of the fracture to the opposite side, which causes the fracture to resist heating. Heat travels from the fracture into the oil shale formation. This process causes solid organic matter within the oil shale to transform into liquid gas and oil. The fractures formed using horizontal wells create a transmissive zone that increases the temperature of oil shale to a pyrolysis temperature. Gas and oil are brought to the surface via horizontal wells separated by vertical producing wells (Kang et al., 2020a; Tanaka et al., 2011). Martemyanov et al. (2016) also documented a new approach to electric thermal technology that is identical to Electrofrac™ technology. Independent Energy Partners' geothermal fuel cell (GFC) technology, which employs fuel cells buried underground, generates a self-contained heat source with low emissions and energy consumption (Crawford et al., 2008; Crawford and Killen, 2010). Within the IEP system, high-temperature fuel cells are placed underground to heat kerogen and release hydrocarbons. Unlike traditional processes, this GFC technology is self-contained, requires minimal external energy, and achieves a 174 kWh/bbl oil-to-electricity conversion ratio with minimal emissions (NOx, SO_2, particulates, or toxins) (Kang et al., 2020a). The different computational simulations evaluated the effects of vertical heater temperature, hydraulic fracture spacing, and horizontal production well placement for the Shell ICP, Steamfrac, and ExxonMobil Electrofrac™ methods. Hascakir et al. (2008) also investigated electrical heating for oil recovery from four oil shale samples that were taken from various Turkish deposits. They blended experiments and computational simulations, including the addition of three types of iron powders to improve oil production by reducing its thickness and attaining effective heat transmission.

In general, as with most types of rocks, oil shale is an insulator of heat; thus, for any electric heating method for oil shale, the *in situ* retorting rate is slow, and the preheating period typically lasts over a year before any oil and gas are generated, leading to lower productivity (Council We, 2004). Approximately 5% of the kerogen in oil shale undergoes complete pyrolysis at ~500 °C to produce oil and gas flow that enables conductive heat transfer; furthermore, the thermal energy produced from the hydrocarbons generated is roughly 5% of the energy required for pyrolysis per unit mass. Thus, the remaining 95% of electrical heating's energy consumption is lost as conduction, forming the primary basis for gradual electrical heating. In addition, producing electrical energy requires an extensive power supply, and the costs associated with perpetual *in situ* electrical heating over a prolonged period frame are high.

4.2. Radiant retorting technology

A significant amount of research focused on using radio frequency (RF) energy to enhance the process of oil shale retorting (Crawford and Killen, 2010; Tahir et al., 2020b) has been published since the 1970s. RF energy in oil shale development can be applied in various forms. Microwaves play a key role in radiation heating technologies, as they transfer electromagnetic energy that affects molecules, which in turn heats rocks and helps break down kerogen into gas and oil. Conventional heating methods are used to retrieve kerogen from the surface without relying on thermal conduction, and certain fluids are injected to aid in this process (Zhu et al., 2021). The reservoir temperature can rapidly increase due to the microwaves' heating power and high radio frequency. The two most advanced radiation heating systems, in theory, are the radio frequency (RF) technology developed by the Lawrence Livermore National Laboratory (LLNL) and the radio frequency-critical fluids (RF/CF) *in situ* mining technology created by Schlumberger. Although there is still a lack of widespread commercial use, these technologies show superior heating mechanisms and efficiency in experimental and pilot studies. As a result, they are still technologically sophisticated but not yet well-established in regular field operations (Chen et al., 2024).

Raytheon Corporation, along with its technical partner CF Technologies, is now part of Schlumberger. Raytheon has

developed an innovative extraction method known as RF/CF technology. This technique utilizes critical fluids (CF) to move the gases and oil produced to production wells and employs radio frequency (RF) to increase the temperature of the shale to that necessary for pyrolysis. This process involves sending RF energy through adjustable RF antennas, or transmitters, that are inserted into the ground to heat the subsurface shale. After the heating and pyrolysis processes are complete, supercritical carbon dioxide is introduced into the shale formations to retrieve the oil from the rock and transport it to an extraction well. Meanwhile, oil and gas are transformed into fuels and other aboveground products, and the carbon dioxide is removed and redirected back into injection wells (Crawford and Killen, 2010; Zhang, 2009).

Phoenix Wyoming, Inc. used microwave heating technology in a borehole (Crawford and Killen, 2010). Shale can be heated with microwave technology up to fifty times faster than traditional electric conduction methods used *in situ*. To showcase the corporate potential of borehole microwave technology for oil shale advancement, Phoenix Wyoming Inc. is investing $15 million into the construction of a pilot plan (Dammer et al., 2007). Furthermore, various experimental studies have shown that using pyrolysis and microwave heating on oil shale can yield premium oil products with impressive heating efficiency. For instance, Mokhlisse et al. (2000) conducted experiments with Moroccan oil shale subjected to pyrolysis by microwave radiation and developed a microwave heating system. Their findings indicate that microwave heating is not only feasible but also results in lower levels of sulfur and nitrogen compared to traditional pyrolysis methods. Other related research has also revealed that oil produced through microwave radiation tends to have higher concentrations of aromatics and saturated alkanes while containing fewer nitrogen and sulfur compounds than oil obtained from conventional heating methods (Wang et al., 2023; Yang et al., 2017).

According to Noble et al. (1981) and Wang and Noble (1983), the results of shale oil yields using microwave radiation at 450 W are similar to those achieved using traditional heating methods. However, once 600 W of microwave radiation is reached, oil output starts to drop. Their work demonstrates that the rapid temperature increase during the pyrolysis of kerogen leads to the pyrolysis reaction of shale oil and the generation of gas. Interestingly, the levels of asphaltene and polar molecules in shale oil produced through microwave radiation are lower compared to those produced by conventional heating (Chen et al., 2024).

Radiant retorting technology requires a significant amount of electrical energy to generate RF energy, which can drive up development costs to reach levels similar to those of Shell ICP. However, if electricity is produced from renewable energy sources such as solar, wind, and geothermal energy for oil shale *in situ* radiation retorting, radiant retorting could have a promising future (Kang et al., 2020a).

4.3. Convection retorting technology

Currently, in-situ retorting methods of oil shale require injecting intense fluids into the formation to improve the production of shale gas and oil. CRUSH (Chevron's technology for the Recovery and Upgrading of oil from Shale), a process developed by Chevron, involves the use of heated gas injection, initially natural gas and then CO_2, through natural or induced fractures to heat kerogen. The process was designed for the creation of a crushed zone with an area of 4000–20,000 m^2 and 15 m thick for efficient pyrolysis. Although lab and small field tests had been planned, the program was discontinued in 2012 (Crawford et al., 2008; Crawford and Killen, 2010). Numerous companies have investigated various in-situ methods for extracting oil from oil shale. Petro Probe Inc. formulated the Petro Probe process of injecting superheated air through a borehole into the shale, thereby liberating hydrocarbons. This method has been shown to generate light shale oil in laboratory tests but has never been tested in the field. American Shale Oil (AMSO) employed a closed-loop heating system utilizing a subsurface burner to heat the oil shale deep beneath the surface. While this method was promising, it was characterized by a faster heating rate than Shell ICP technology, which had suspended field testing because of trouble with the downhole burner. In May 2016, it was announced that the AMSO project was closed. Mountain West Energy (MWE) developed an *in situ* vapor extraction process in which hot gas is injected directly into the shale to vaporize oil, which is brought to the surface and then condensed. This project offers an alternative *in situ* retorting method since vapor rather than liquid oil is brought to the surface. MWE computer modeling and partial field trials produced a bubble of gas surrounding the well, and it is one of the few companies testing unconventional oil recovery in the field (Kang et al., 2020a).

In 2014, Unity & Strength Co., Ltd. efficiently produced China's inaugural *in situ* shale oil barrel from oil shale formation 300 m below the ground in Songyuan, Jilin Province. The company is working on a new *in situ* approach called in-situ fracturing chemical-developing technology (ICFD) to recover oil and gas from oil shales. This process includes igniting flammable gas in an ignition chamber within the injection well to generate hot fluid gas, which is forced through a small fracture (1–3 mm in length) in the shale to decompose the kerogen (Ma et al., 2019).

MTI technology, which uses the process of steam injection for oil shale *in situ* retorting, was conceived by Zhao et al. (2005) and is defined as a steam injection method. Scientists are still looking into the impacts of steam and other gases on oil production, despite more conventional methods such as AMSO and CRUSH having been abandoned. Steam injection was previously considered to be ineffective according to a 3D model in Turkey; however, that particular study only tested low temperatures (Kök et al., 2008). Later research found that steam enhances oil yield at elevated temperatures. Experiments with Bulgarian oil shale, for example, showed a 20% higher oil yield compared to traditional methods (Razvigorova et al., 2008). Experiments on Jordanian oil shale using gases including nitrogen, CO_2, and supercritical fluids revealed that supercritical water gave the best results, enhancing oil yield by 50%, whereas supercritical CO_2 gave the worst yield due to inefficient pyrolysis. Further studies on the integration of Lignite and oil shale showed less water usage and more oil production. Steam performed better than electric heating in hot-test runs. Laboratory tests on Chinese oil shale revealed that steam enhances oil yield and quality apart from facilitating the breaking down of the shale, especially when metallic ions act as catalysts. Ultimately, steam is effective as a chemical agent and a source of heat to promote shale oil recovery from oil shale (Kang et al., 2020a).

Several studies on fluid-fracturing techniques in oil shale reservoirs have enhanced operational practice. To ensure system balance, Chen et al. (2017) created a method in which high-pressure nitrogen drives out fissure groundwater from fissures. Pulse power fracturing (PPFT) is another such method, which was effectively tested in Maoming and showed the capability to fracture shale as far as 15 m (Gao et al., 2016). One method that involved mixing superheated steam and horizontal fracturing helped in the extraction of shale oil from depths of 300–1000 m at Huangxian (Wang et al., 2014a). Zhao (2016) pioneered and patented processes involving horizontal and vertical wells, combining fracturing with chemical heating to yield

hydrocarbons. The structure of the rock changes during the transformation of kerogen to gas and oil, resulting in complex mechanical behavior. Zhang and Parker (2010) created a model that shows how physical factors play a role in how heat moves from fissures to rock. Zhao (2016) contributed to a method for creating more cracks and allowing gas and oil to flow, finding that the internal pressure of the reservoir must be higher than the breaking point of the rock. While this is difficult to apply in practice, Zhao (2016) recommended the use of compressed air to break up big shale blocks into pieces earlier on in the open-hearth process.

Many scientists have examined how oil shale degrades (pyrolysis) under heat by fluids. Chen et al. (2016) discovered that the minerals present in oil shale accelerate the transformation of kerogen to bitumen and that the reaction is better facilitated compared to pure kerogen. Several experiments have also investigated how heating rates influence the quality of oil obtained. Lan et al. (2015) found that an increased amount of shale oil was produced with an increase in thermal range from 475 °C to 1000 °C and that the gas contained slightly more alkenes. Allawzi et al. (2011) attempted to extract oil from Jordanian shale with supercritical CO_2 and solvents such as hexane and acetone and achieved the best results at 450 °C and 3200 psi. This combination enhanced oil extraction by increasing kerogen's solubility. Another study created a model demonstrating oil shale's behavior under the application of heat and pressure (Allawzi et al., 2011). Two bacteria-based bioleaching enhanced oil yield by 15% and minimized gas loss (Zhang and Li, 2017). Computer simulations by Youtsos et al. (2013) demonstrated that when heating, the zone of chemical reaction follows the wave of heat. A study in China concluded that currently, only shale with high oil content (above 18%) is appropriate for *in situ* fluid heating (Ahmad et al., 2021; Kang et al., 2020a).

4.4. Combustion heating technology

In situ combustion methods employ the use of some of the shale itself to heat the remainder of the formation. The United States began applying oil shale *in situ* combustion demonstration projects for gas and oil recovery as early as the 1970s in locations south of Vernal, Utah (Hutchinson, 1980) and near Rock Springs, Wyoming (Burwell et al., 1970). The oil shale is first set on fire within the injection wells and subjected to a constant injection of air to develop and sustain a burning front following the fracturing of the oil shale using hydraulic fracturing and an eruption to develop permeable pathways. Based on the test results, an oil shale self-sustaining combustion zone can be created. This process generates shale oil, which can have adverse consequences on the environment. The low world oil price and increasing project cost estimates resulted in the abandonment of the development of oil shales in most of the United States by the mid-1980s (Crawford et al., 2008).

Jilin University came up with an alternative technique for extracting oil from oil shales buried underground, known as Topochemical Synthesis-Air (TS-A) technology (Sun et al., 2017). This technique involves the use of a hot mixture of air and nitrogen to cause a chemical reaction underground that emits heat. The oil shale consists of kerogen; it breaks down by heat to extract oil. The reaction gradually propagates through the rock, and the oil is pumped to the surface via wells. In 2014, this technique was experimented with in Jilin Province, China, and effectively yielded 1.649 tons of shale oil, with an impressive oil production rate of 78.5% (Kang et al., 2020a; Sun et al., 2017). TS-A is unique because it employs a chemical heat-generating process that conserves energy and allows more oil to be extracted from the shale. Many experimental and theoretical studies have focused on pyrolytic impact, semicoke properties, and oil products in distinct combustion routes (Branch, 1979). Branch (1979) noted issues such as how unpredictable kerogen and other materials can be broken down. Experiments on Huadian oil shale revealed that pyrolysis predominantly occurs between 400 °C and 500 °C (Jiang et al., 2007). The rate at which combustion weight changes with temperature in TS-A technology is less than that of pyrolysis. (300°C-500 °C).

Kok and Bagci (2010) investigated the Beypazari oil shale's combustion pyrolysis process, which is categorized into two distinct zones of temperature: the zone of decomposition by combustion and the zone of oxidation at high temperatures. The oil shale deposit in this area is believed to be appropriate for mining with *in situ* combustion technology. Moreover, Zhao et al. (2013) concluded that the temperature of oil shale must exceed 1000 °C, which is necessary for oil and gas recovery, after conducting an underground co-gasification model test to determine whether *in situ* exploration of oil shale via underground coal gasification is feasible. Martins et al. (2010) examined the chemical characteristics of Timahdit oil shale and the gaseous byproducts of thermal degradation, finding that around 52% of the organic matter in oil shale was transformed into liquid oil and that the gas produced had a reduced calorific value of 53.9 kJ/mol. Martins et al. (2010) also characterized the geometry of a combustion front transmitting with a co-current descending air supply in Timahdit oil shale as the porous medium, discovering that the combustion zone spread horizontally as a planar circle with a maximum temperature of 1100 °C and an estimated heat loss of 42%. Additionally, Guo et al. (2016) determined that the oil shale retorting depends on the calorific value of the semicoke of remaining carbon after combustion above 500 °C. A simulation study completed on the *in situ* combustion of oil shale described the underlying behaviors of multiple gases in and through chemical pathways that occur during the process of simulating *in situ* combustion in underground rock strata, the results from this study showed that the volumes of gas injected and the levels of oxygen are significant considerations in facilitating effective transitions from simulation studies to real-life testing (Zheng et al., 2017). Water and specialized chemicals (catalysts) are also significant in this process because they lower the temperatures needed for kerogen breakdown and provide the temperature needed to heat the rock for a shorter amount of time (Kar and Hascakir, 2017; Zheng et al., 2017). Solum et al. (2014) used a model consisting of four reactions to examine the thermal oxidation of organic matter observed in oil shale. Heavy oil (bitumen) was the first model reaction, while the second model reaction addressed the gaseous components of kerogen. The third model reaction focused on larger macromolecules (the physical size of those larger than kerogen molecules), and the fourth model reaction addressed solid carbon, which makes up the fixed carbon mass. The researchers sought to examine the impacts of the chemical structure of oil shale on the degradation of oil shale once heated (Fletcher et al., 2014; Hillier et al., 2013). However, the entire process is challenging to manage, as it is difficult to maintain the proper underground combustion level and to move the heat exactly where it is needed. Additional effort and research will be needed before *in situ* combustion can be viably used for oil shale extraction (Kang et al., 2020a).

5. Injection technologies for oil shale *in situ* conversion

5.1. Nitrogen injection technology

In situ conversion is an advanced technology used to create oil shale and ultra-heavy oils that are impossible to extract using

traditional methods (Pei et al., 2018). ICP technology employs the cracking of light oils and gases from kerogen or heavy components. This process is achieved by pyrolysis and underground heating. Gas injections are the most popular technique for enhanced oil recovery (Vinegar, 2006), while nitrogen injection is the most common and economically friendly method used for ICP, which, depending on the oil's composition and pressure, can be either miscible or immiscible (Economides et al., 2012; Taber et al., 1997). Nitrogen injections were first introduced in the 1940s, and the first nitrogen injection project began in the West Texas tight reservoirs in 1945 (Mogensen and Xu, 2020). The Nitrogen-Assisted In-situ Conversion Process (NAICP) combines electrical heating with nitrogen injections to facilitate the movement of the reservoir oils. Kerogen and other heavy organic hydrocarbon components are pyrolyzed during NAICP and ICP, according to the work of Braun and Burnham (1992).

Nitrogen injections are conducted by placing electric heaters hexagonally to pyrolyze kerogen. Injections are then initiated 90 days after heating, which improves convection-based heating and aids in pressurization and the displacement of retorted oil from oil shale. Nitrogen increases heating rates by 65% (Liu et al., 2009). At low injection rates and moderate heating temperatures, NAICP showed significantly more energy preservation than regular ICP. Along with the pyrolysis and fluid expansion caused by heating, oil shale's porosity and permeability can change during ICP and NAICP. Oil shale usually has a permeability of 0.0001–0.1 millidarcies (mD) and an initial porosity of 0%–5%. However, following kerogen pyrolysis, permeability can reach about 1 mD, and porosity can rise to 30%, improving the flow of the produced oil through the fractured rock (Kibodeaux, 2014). Moreover, heating thermal flux is boosted by nitrogen injections. To increase the efficiency of kerogen conversion, the NAICP technology uses heat convection from gas injections to speed up thermal conduction. The injected gas flows more quickly than the gases produced *in situ*, and the heat transfer rate shortens effective processing time and increases production efficiency. The accelerated heat transfer resulting from this technology leads to a faster *in situ* kerogen conversion rate and more effective permeability porosity of rock, as well as fluids. The average formation temperature evolution for pure NAICP and ICP is shown in Fig. 10. The convection heat transfer effect brought on by the nitrogen injection is reflected in the difference between these two temperature profiles. The S1/S2 ratio is an indicator of how nitrogen-driven convective heat transfer affects the rate at which the formation temperature rises. Fig. 11 shows the results of the simulation, which examined heater thermal range (300°C-600 °C) and nitrogen injection rates (50–1600 Sm^3/day).

The S1/S2 ratio can reach a maximum of 0.65 when the nitrogen injection rate reaches 1600 Sm^3/day, indicating a possible 65% increase in heat transfer efficiency as a result of nitrogen injection. The effect of convective heat transfer intensifies as the nitrogen injection rate rises in an almost linear upward trend. Furthermore, higher heater temperatures yield greater S_1/S_2 values than lower temperatures for a given nitrogen flow rate. Based on the pressure at reservoir temperature, nitrogen injection can either be miscible or immiscible. A nitrogen injection is miscible when there is no interfacial region between the displacing phase and the reservoir (Fathinasab et al., 2015). The ability of nitrogen injection to attenuate irreducibility has led to its prioritization over other EOR methods. Nitrogen injections offer several advantages over other EOR methods. For example, modern, affordable technologies make it simple to remove nitrogen from the atmosphere. As nitrogen is an inert gas, it has a very low effect on the pyrolysis of kerogen, and it also prevents the corrosion of downhole equipment and pipes. Additionally, nitrogen gas is less expensive than other gases, has a minimal corrosion effect on downhole pipes and equipment, and is easy to process post gas because of its lower solubility (Pei et al., 2018; Su et al., 2020).

The cumulative volumes of nitrogen produced and injected are shown in Fig. 12, which shows that both curves completely overlap. This overlap indicates effective gas channeling and movement within the oil shale reservoir's fractures. Gas channeling enhances the thermal interaction between the nitrogen and the oil shale, which is beneficial in this situation despite it being typically viewed as an undesirable outcome in conventional oil reservoirs (Chen et al., 2014; Yuncong et al., 2014). The ability to fully recover, recompress, and reuse the injected nitrogen for reinjection reduces overall operating costs (Fig. 12).

Determining the economic viability of thermal recovery techniques such as the nitrogen injection–assisted *in situ* conversion process (NAICP) requires an evaluation of energy efficiency. Two important metrics were employed by Pei et al. (2018) in this regard: energy conversion ratio (ECR) and cumulative energy-to-oil ratio (CEOR). Their simulations demonstrated that, especially under moderate conditions (300°C-400 °C) and rates of nitrogen injection of (50–400 Sm^3/day), NAICP reduces energy consumption at a considerably higher rate compared to conventional ICP. The energy conversion ratio increased to 9.5 under these conditions, demonstrating effective oil production (Fig. 13). Higher injection rates, however, decreased efficiency because of diminishing returns and heat loss. This emphasizes how optimizing injection and heating parameters for operations that are both economical and energy-efficient is crucial (Pei et al., 2018).

5.2. Steam injection technology

Steam injections constitute a convection-based heating technology that is particularly used for heavy oil reservoirs (oil shale), where it is applied to enhance the oil's viscosity and improve the movement through the reservoir (Vega Riveros and Barrios, 2011). This technique includes the injection of high-quality saturated steam into the reservoir, which enables the transportation of large quantities of thermal energy with minimal temperature waste (Thoram and Ehlig-Economides, 2011). Petro Probe Inc. developed an injection system for superheated air (the Petro Probe process) (Crawford et al., 2008; Zafar et al., 2021). Air with a regulated oxygen content is thermally energized in a burner and released into the ground, works as a heating agent, and blows a well. This air scours the surfaces of the rock, with the shale and most of the

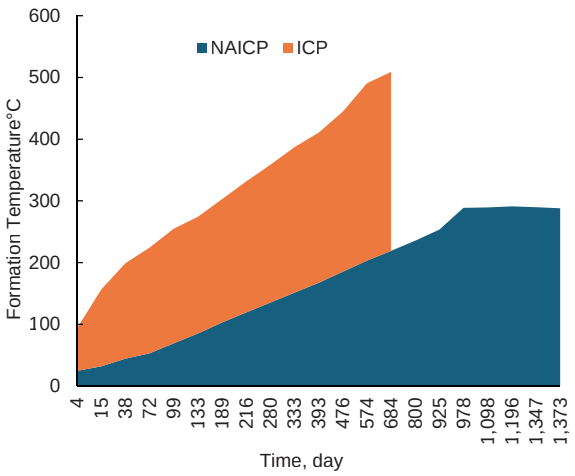


Fig. 10. Change in average formation temperature throughout the ICP (Pei et al., 2018).

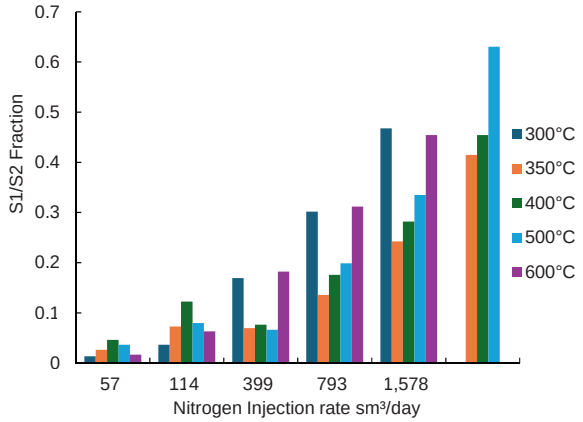


Fig. 11. Heat convection effect of nitrogen at various temperatures and gas injection rates (Pei et al., 2018).

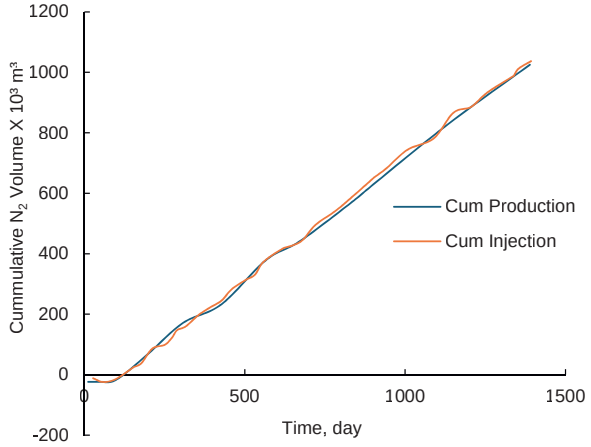


Fig. 12. Cumulative nitrogen injection and production of NAICP (Pei et al., 2018).

water carried back to the surface by the exhaust gases. Light hydrocarbon gases and liquids are produced by the condensation of the hydrocarbons that rise to the surface. No testing has been conducted in the fields yet, but oil with 45 API gravity has been measured in the lab using this technology (Kang et al., 2020a).

Research on the technology and theory of the oil shale underground retorting alongside experimental research work has been conducted by researchers of TYUT over the previous several decades (Geng et al., 2017; Wang et al., 2018c). In 2010, the TYUT team was awarded a Chinese patent for their method of extracting oil and gas from oil shale by convection heating (Zhao et al., 2005). The organic components contained in oil shale are highly sensitive to variations in thermal conditions because they are likely to undergo a strong thermal degradation reaction, which can lead to the production of high amounts of shale gas and oil at times when the temperature rises from 350 °C to 550 °C (Doğ;an and Uysal, 1996). The use of superheated steam injection for oil shale *in situ* retorting, also named modified thermal injection (MTI) technology (Wang et al., 2019c), is a productive approach for the acceleration of the recovery from oil shale resources whose operational stages can be outlined as follows:

1) There are more than 50 m between the numerous boreholes that are drilled into the ground and the oil shale formation. Fracturing methods can improve connectivity between production and injection wells.

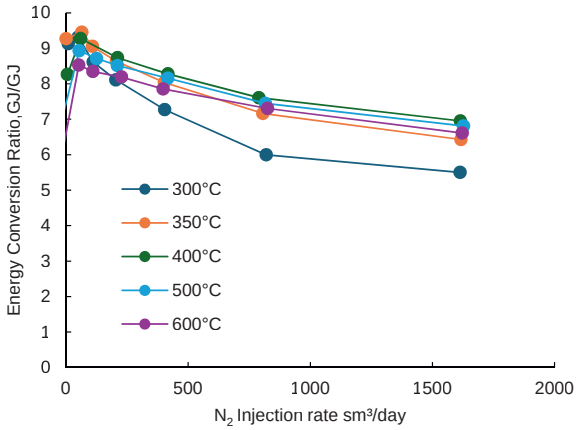


Fig. 13. Impact of nitrogen injection rate on ICP and NAICP energy conversion ratios (ICP projects are indicated by a nitrogen injection rate of zero) (Pei et al., 2018).

2) Oil shale deposits are injected with superheated steam of temperatures greater than 500 °C. via specified injection wells using an underground piping network. This injection heats the deposit as well as degrades organic matter, thus producing various oil and gas products.
3) Gas and oil products are carried out via low-temperature steam (or condensed water), typically in the range of 100°C–200 °C, from production wells toward the surface and through a separation process toward final gas and oil product recovery, followed by the purification and recycling of condensed water (Kang et al., 2020a, 2020b). Fig. 14 presents a diagram of MTI technology and its main operating principle.

Through the constant pressure of heat, oil shale is subject to continuous thermal cracking and pyrolysis, forming a significant number of fractures and new pores and an interconnected oil and gas flow network as a result. The heated fluid flows through each part of the deposit of oil shale and is handled by a perforated pipe. Oil shale continues to undergo pyrolysis while producing oil and gas. Kang et al. (2020b) conducted a pilot test from 2014 to 2016 using 2.2 m oil shale samples, which verified the strong prospects of commercial oil shale development utilizing MTI technology. The pressure of injected steam in the reaction zone during the *in situ* conversion process is purposefully kept below 25% of the overburden stress to prevent fracturing and guarantee process control. The sequence of variations in pressure and temperature is completely controlled by steam seepage (Kang et al., 2020a). Advancements in steam injections, in contrast, have been relatively limited, but the technology still holds considerable potential. The results of the experimental tests show that superheated steam injection can attain temperatures higher than 426 °C, and oil recovery factors in a range between 60% and 95% have been observed for lighter shale oil (Kang et al., 2020a; Yang et al., 2021). Ultimately, superheated steam was verified to be the most used thermal transfer fluid in *in situ* oil shale pyrolysis.

The technical specifications of this invention are as follows. A properly constructed system of wells spaced 50–200 m from one another, set to drill horizontal hydraulic fractures, is designed for optimal drilling and maximum ore control. The anisotropic strength of oil shale allows for hydraulic fractures to propagate along bedding planes, improving well connectivity using horizontal hydraulic fracturing in a controlled manner, based on existing patents. The walls of the larger fractures provide an efficient path for heat to flow and to pyrolyze sustainably.

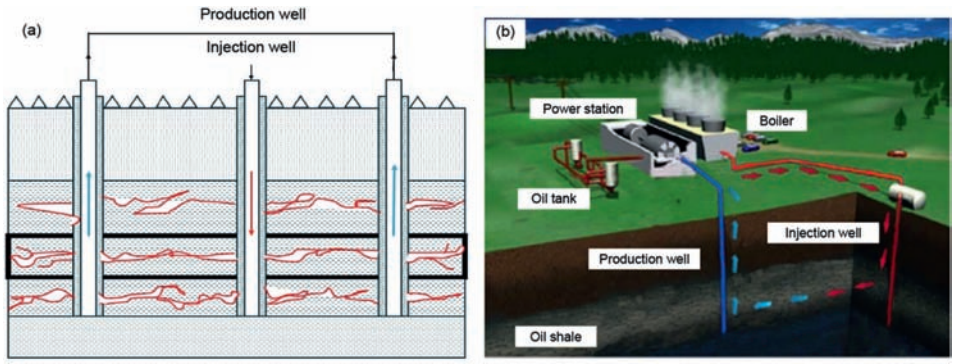


Fig. 14. The injected superheated steam (MTI) *in situ* convection technology for oil shale: (a) hydraulic fracturing; (b) MTI system schematic (Kang et al., 2020a).

Superheated steam at temperatures above 500 °C breaks down organic matter. Each of the wells can be used to alternate and inject steam or be produced, allowing for the flexible control of the pyrolysis zone (Britton et al., 1981; Eseme et al., 2007). The energy utilization ratio and gas and oil output rate both rise as the steam temperature rises when MTI technology is used. On the other hand, most *in situ* retorting systems for oil shale prefer to inject N_2, CO_2, and other gases at high pressures and temperatures.The quantitative comparison summarized in Table 2 demonstrates notable differences between nitrogen injection and steam injection technologies for in situ oil shale conversion, particularly with respect to conversion efficiency and resource utilization.

6. Emerging diagnostic and analytical methods for oil shale

6.1. Sub- and near-critical water methods

In situ techniques may be conducted underground without shale mining and can be used to successfully extract oil from oil shale within subcritical and near-critical water. Due to its wider scope and experimental conditions, subcritical water is more often used in the extraction of oil shale than near-critical water. Students and teachers at Jilin University are among the main researchers of oil shale extraction using near-critical and subcritical water (Deng et al., 2011). Wang and Li (2019) classified superheated water (water at temperatures ranging from 150 °C to 374 °C and pressures from 0.4 MPa to 22.1 MPa) as near-critical water. Subcritical water, also known as low-temperature superheated water, is at similar pressures but temperatures slightly below the critical point (100 °C–374 °C). Both states of water are environmentally friendly, non-toxic, and cheap solvents; therefore, they are attractive alternatives for oil extraction (Wang and Li, 2019). Subcritical water recovered roughly 7% of oil in 2–5 h at 260 °C and at 15 MPa, while near-critical water recovered as much as 1%–18% in 70 h, indicating it to be superior to traditional methods according to laboratory tests. The experiments employ reactors at high temperatures and pressures, and sophisticated analytical equipment such as GC-MS is used to examine the composition of the produced oil (Wang and Li, 2019).

An experiment of this type would typically require a reactor capable of maintaining the experimental generator at a high temperature and pressure. The uninterrupted extraction was accomplished for multiple hours in near-critical and subcritical water, and the extract components were analyzed. The gathered experimental data were sufficient to analyze and demonstrate the findings. Fig. 15 shows the complete experiment. Wang et al. (2014c) carried out an experiment using near-critical water to withdraw organic matter from oil shale. The experimental work studied the effects of factors such as temperature, shale asphaltene content, and porosity on yields. Wang and Li. (2019) concluded that near-critical water extraction can be effective with the Huadian oil shale attaining up to 18.1% oil recovery for the experimental conditions used and over 70 h, more than conventional extraction (Wang and Li, 2019). Wang et al. (2014c) screened several larger blocks of oil shale and demonstrated that near-critical water can be particularly effective at extracting oil shale oil, again suggesting the potential of an underground *in situ* oil shale extraction process. Alhesan et al. (2019) extracted marine oil shale using the traditional HCl–HF method; they also compared their observed results with the NaOH–HF extraction and discovered that near-critical water recovery was more effective than NaOH–HF extraction at oil recovery. This comparison provided

Table 2
Quantitative comparison of nitrogen injection and steam injection technologies for *in situ* oil shale conversion.

Parameter	Nitrogen Injection	Steam Injection
Heating mechanism	Convection-based gas injection (N_2) + electric heating (NAICP)	Convection-based fluid injection (superheated steam)
Temperature range	300°C-600 °C	350°C-550 °C (superheated steam >500 °C)
Porosity & permeability change	Porosity of up to 0.30; permeability of up to ~1 mD (Kibodeaux, 2014)	Significant pore and fracture development; up to 60–95% recovery observed
Heating rate efficiency	Increases heating rate by ~65% (Liu et al., 2009)	Steam enhances pyrolysis and improves recovery efficiency
Oil recovery factor	Depends on injection rate and temperature; efficiency increases up to the optimal level and then declines	60%–95% recovery observed in pilot tests
Energy efficiency	Energy conversion ratio of up to 9.5 (Pei et al., 2018)	High thermal efficiency, continuous heating, and recycling of condensed water
Advantages	Low cost, inert, easy to separate and recycle, and environmentally safer	Strong heat transfer, effective pyrolysis, and high oil recovery
Limitations	Efficiency declines at high injection rates due to heat loss	Requires high steam temp (>500 °C), risk of fracturing, and high water consumption

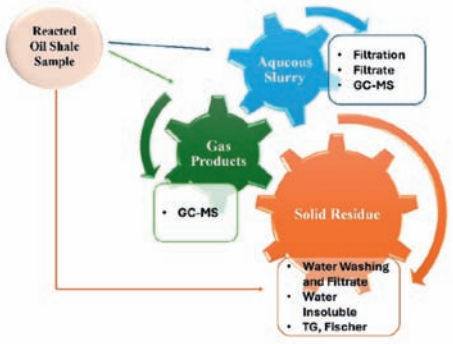


Fig. 15. Stepwise diagram illustrating how the extraction experiment is undertaken and how findings are evaluated and analyzed (Wang and Li, 2019).

evidence that near-critical water recovery was more productive and promising for organic matter extraction from oil shale.

Previous research has demonstrated that oil shales from different areas have unique physical properties, resulting in variation of extraction results (Dyni, 2003; Jin et al., 2012). No general approach that works for all oil shale conditions currently exists, as they are all inherently different. Oil shales are also subjected to high enough temperatures during the pyrolysis process that the physical attributes of the oil shale are often overlooked before the extraction process. The final objective of the use of near-critical and subcritical water is the implementation of this technology for the *in situ* (underground) oil shale method. Research in this area, however, is still quite limited, with major challenges such as the different underground conditions of temperature, how much range heat can be extended, how water should be used, and whether the flow works underground. A single temperature change has implications for permeability and porosity, which are directly correlated to the flow and recoverability of oil and gas products. As noted earlier, laboratory experiments are constrained, and researchers must use simulations to model and understand phenomena.

To date, near-critical and subcritical water has been used in lab experiments based on current research to recover organic matter from oil shale (Gu et al., 2024; Sun et al., 2019b). Chemical experiments were used to evaluate the process and examine the products in these studies. These products are typically evaluated using GC-MS analysis, and they are sometimes studied in the same way as ground distillation. A thermal gravimetric analysis evaluation has also been conducted throughout an experiment to observe long-term process evaluations (Wang and Li, 2019).

6.2. Terahertz spectroscopy in oil shale

Oil shale contains many interacting parts that mix in complex ways, such as organic materials and minerals. This complexity makes it difficult to clearly understand how much oil can be produced from oil shale and how this production process functions. This has made it challenging to determine the most effective methods for developing oil shale (Han et al., 2009; Saif et al., 2019). Several methods have been used to evaluate oil shale, including thermogravimetry analysis (TGA), Raman spectroscopy, X-ray diffraction, well logging, mass spectroscopy, Fourier transform infrared spectroscopy (FTIR), and nuclear magnetic resonance (NMR) (Bai et al., 2015; Lin et al., 2016). Methods such as transmission electron microscopy (TEM), scanning electron microscopy (SEM), and computed tomography (CT) have been employed for the compositional analysis of kerogen and pores in oil shale (Wang et al., 2018d; Zhan et al., 2020a). Terahertz (THz) spectroscopy is currently regarded as a crucial cutting-edge technology, as it offers features such as fingerprint spectroscopy, a broad frequency range, and low energy penetration. Poor chemistry between molecules, dipole rotation, macromolecule skeleton vibration, single phase, the lattices' moderately low-frequency oscillations, and the operation assimilation of all the crystals, all match the terahertz band range, which is ideal for macromolecules' large and slow movement and for a strong response to polar compounds (Miao et al., 2018; Xie et al., 2014). Relating optical parameters to physical properties based on the interactions of THz waves with various materials enables the improvement of the characterization and analysis of the structural, compositional, and physical characteristics of the oil shale material. Investigating ultrafast dynamics can be achieved in picoseconds in the presence of stimulated or external field conditions. Furthermore, the THz spectrum demonstrates the alterations in the electric potential field over time and has been used in fields such as the characterization of material properties (Cheikh Moine et al., 2016; Su et al., 2014). Terahertz technologies make up a developing analysis approach in the oil and gas technology industry and have proven their scientific and practical value in various aspects of describing the structure of gas and oil reservoirs. Dorney et al. (2001) used a single-iteration THz-simulated acquisition using generated pulses and image refinement in geologic surveys, achieving precise reconstruction of the position and shape of the detection target (Yasir et al., 2020a). Greeney and Scales (2007, 2012) simulated a rock surface by employing a conical dielectric waveguide as an examination subterahertz wave vector network analyzer. The assessment of geologic diagenesis, the theory of evolution, oil-bearing reservoir rock, rock porosity, oil and water dispersion in the core with low permeability, well forecasting, crude oil emulsion process, and pattern change have been explored in recent years through the use of THz time-resolved spectroscopy (Meng et al., 2022; Miao et al., 2017a).

Numerous techniques, such as X-ray microscope imaging, acoustics, conductivity, and anisotropy of magnetic susceptibility (AMS), can be used to detect oil shale's anisotropic behavior and textural composition, which are associated with the physical characteristics of the rock, such as texture, composition, and porosity (Bhargava et al., 2005; Jia et al., 2012). However, due to technological challenges, dielectric constant measurement methods have not yet been the subject of widespread adoption. Recent studies have revealed limitations to the Terahertz time-domain spectroscopy (THz–TDS) tests used to measure shale anisotropy (Liu et al., 2023). Sanjuan et al. (2022) retrieved a 3D dielectric permittivity fabric from the anisotropy THz data (Zhan et al., 2020b). The mechanical characteristics of oil shale that are associated with drilling success and good stability are partially influenced by OM, the earliest material exhibiting significant variability within fractures, pores, and matrix (2,6,66,67) (Liu et al., 2023). Assessing the organic matter distribution and content when developing geological models (Guo et al., 2015; Wang et al., 2014b) is crucial. To ascertain the fundamental properties of a typical sedimentary rock, the elements, organics, and minerals of a typical oil shale (sedimentary rock rich in kerogen) have been examined using IR, XRD, SEM, TEM, and energy dispersive X-ray spectroscopy (Zhan et al., 2020a, 2020b). Since the change of n is equal to the THz characteristic index(n) of the medium, THz parameters can be used to better determine the mechanical properties of oil (Miao et al., 2017b; Schwerdtfeger et al., 2013). Diagenesis, metamorphism, and metamorphism are the three stages of the hydrocarbon evolution of sedimentary OMs like kerogen (Durand, 2003). At different stages of evolution, the composition and structure of kerogen undergo significant changes with the generation of oil and gas. This process alters the THz absorption

coefficients of gas and oil, which are strongly influenced by the level of kerogen evolution. To elucidate how kerogen evolves and its ability to produce hydrocarbons, Bao et al. (2013) employed THz–TDS, a preservation-friendly and contactless technique. The THz value represents the Kerogen maturation process at various pressures and temperatures (Durand, 2003). Kerogen maturity levels were classified as immature (IM), early mature (EM), middle mature (MM), late mature (LM), and over mature (OM) at varying simulated temperatures (TS). The stages of hydrocarbon evolution were found to correlate with the THz optical constant curve of kerogen. Vitrinite reflectance (R_o) is a measure of how much light reflects off a smooth vitrinite surface. This reflection changes as the vitrinite matures over time and is a common method of determining the maturity level of kerogens, which are organic materials found in rocks (Dorney et al., 2003; Zich et al., 2013).

THz's capacity to simultaneously characterize the zone of natural gas and the main oil generation zone through THz spectroscopy, which is challenging to obtain with traditional techniques like R0%, constitutes a significant breakthrough in THz wave exploration. This contrasts with the primary hydrocarbon generation zone, which can be immediately identified using R_o. Additionally, a correlation between the oil content of semicoke and THz absorption can be drawn: the key threshold of THz absorption closely matches the rate of oil production (Bao et al., 2016; Huber et al., 2008). Techniques such as THz prospecting and thermal terahertz analysis (TTA) were previously used to detect organic matter and explore desert reservoirs, respectively (Liu et al., 2023). Unconventional oil and gas reservoirs are characterized by low porosity, low permeability, and high density, suggesting that improvements in nanoscale resolution are crucial for using THz technology to characterize these unconventional hydrocarbon resources. THz dispersion at nanoscale probes has been found to allow terahertz near-field imaging to achieve ultrafine resolutions (Ma et al., 2013; Riley et al., 2012).The applications of THz spectroscopy are shown in Fig. 16.

Although the direct *in situ* application of terahertz (THz) technology for oil shale remains underexplored, several studies have demonstrated its potential under laboratory conditions. Zhan et al. (2015) applied THz-TDS to monitor oil shale pyrolysis stages, linking spectral changes with kerogen and mineral decomposition, validated against TGA, MS, SEM, and XRD (Liu et al., 2023). Qin et al. (2021) introduced TTA to detect trace organic matter during pyrolysis in the range of 300°C-600 °C. More recently, Liu et al. (2023) reviewed advances in oil shale pyrolysis, highlighting the role of THz in tracking organic matter evolution and kerogen degradation. Most studies remain laboratory based, although recent advances suggest promising pathways for future *in situ* applications. These studies provide a foundation for THz-based pyrolysis analysis despite true *in situ* implementation in reservoir conditions remaining a future challenge.

7. Environmental difficulties of *in situ* conversion technology for oil shale

Comparing the oil shale *in situ* conversion technology to conventional aboveground retorting techniques, it can be found that the former has several benefits over the latter (Al-Ayed et al., 2010; Yang et al., 2016b). The *in situ* conversion technology does not require mining or crushing rock; this lowers costs and makes it technically appropriate for thin or deep oil shale layers (Jaber and Probert, 1999; Routson et al., 1979). Additionally, this method produces far fewer hazardous gases and liquids than traditional techniques, lowering its air pollution and impact on the surrounding environment by eliminating the need to handle large amounts of solid waste (Crawford and Killen, 2010; Raukas and Punning, 2009).

The *in situ* conversion technology still results in several environmental issues. Hazardous compounds such as sulfides, nitrides, BTEX (benzene, toluene, ethylbenzene, and xylene), total organic carbon (TOC), and total petroleum-based hydrocarbon (TPH) (Hu et al., 2019; Yang et al., 2018) are released during the heating process, also known as pyrolysis. These contaminants can potentially seep into groundwater, or underground water. Moreover, these contaminants are hazardous and could impact local sources of drinking water. Additionally, the heating process breaks the solid shale and creates pores and cracks, rearranging it into a loose formation. These fissures may result in contamination, and could allow oil to seep into lower water zones and gases to rise into upper water layers (Wang et al., 2018e). At the same time, these fissures could allow groundwater to enter the heating zone, thereby reducing oil production efficiency. As a result, the primary environmental challenge of *in situ* conversion involves isolating the heating zone from the surrounding groundwater and establishing a sealed system (Kang et al., 2020a; Yasir et al., 2020b).

Companies and researchers have created various sealing technologies to solve this problem. Shell employs a technique known as the freeze wall method. In this method, the ground surrounding the oil shale zone is frozen to create a barrier that prevents groundwater from entering. However, this free wall can take up to two years to build, and it is very costly, particularly for large projects (Brandt, 2008; Ryan et al., 2010). An additional technique is the grouting curtain, which is similar to the way in which dams prevent water leaks. Cement slurry is injected in pores and fractures in the ground surrounding the heating zone (Rafi and Stille, 2015). When the cement solidifies, it creates a water-blocking wall. According to several tests, this wall's sealing effect is improved when the injection wells are arranged in a hexagonal pattern, particularly when the wells are spaced about 3 m apart. While this approach works well, it is quite expensive (Canoğlu, 2019; Guo et al., 2020). To decrease costs, Jilin University came up with a new idea known as marginal gas injection, this approach involves injecting high-pressure gas through wells surrounding the heating zone, the gas forms a sealed area by pushing groundwater away; this method minimizes groundwater entry into the heating zone by balancing gas pressure, water pressure, and capillary force, and can effectively and economically restrict water according to several tests and simulations (Liu et al., 2020; Sun et al., 2019a).

In summary, the *in situ* conversion is easier and cleaner in places without groundwater nearby. However, additional researches are required to identify more affordable, environmentally friendly, and easily implementable sealing techniques for areas with groundwater, so that this *in situ* conversion can be used safely and cost-effectively on a large scale.

8. Future research directions

Despite significant progress in this area, additional researches are needed to allow *in situ* oil shale conversion technologies to move from experimental ideas into use in large-scale applications. Recent studies reveal the need to optimize nitrogen injection pressure and temperature, which will improve sealing efficiency and elucidate the long-term effects of nitrogen on reservoir geomechanics and hydrocarbon recovery (Wang et al., 2024). Ongoing challenges for steam injections include reducing thermal losses, minimizing water demand, and decreasing corrosion. Research also suggests that combining steam with solvents or catalysts may improve overall conversion efficiency and lessen environmental impact (Zhang et al., 2024). The application of THz spectroscopy is still in its early stages; however, it holds great potential as a diagnostic tool. Future efforts should focus on creating calibration

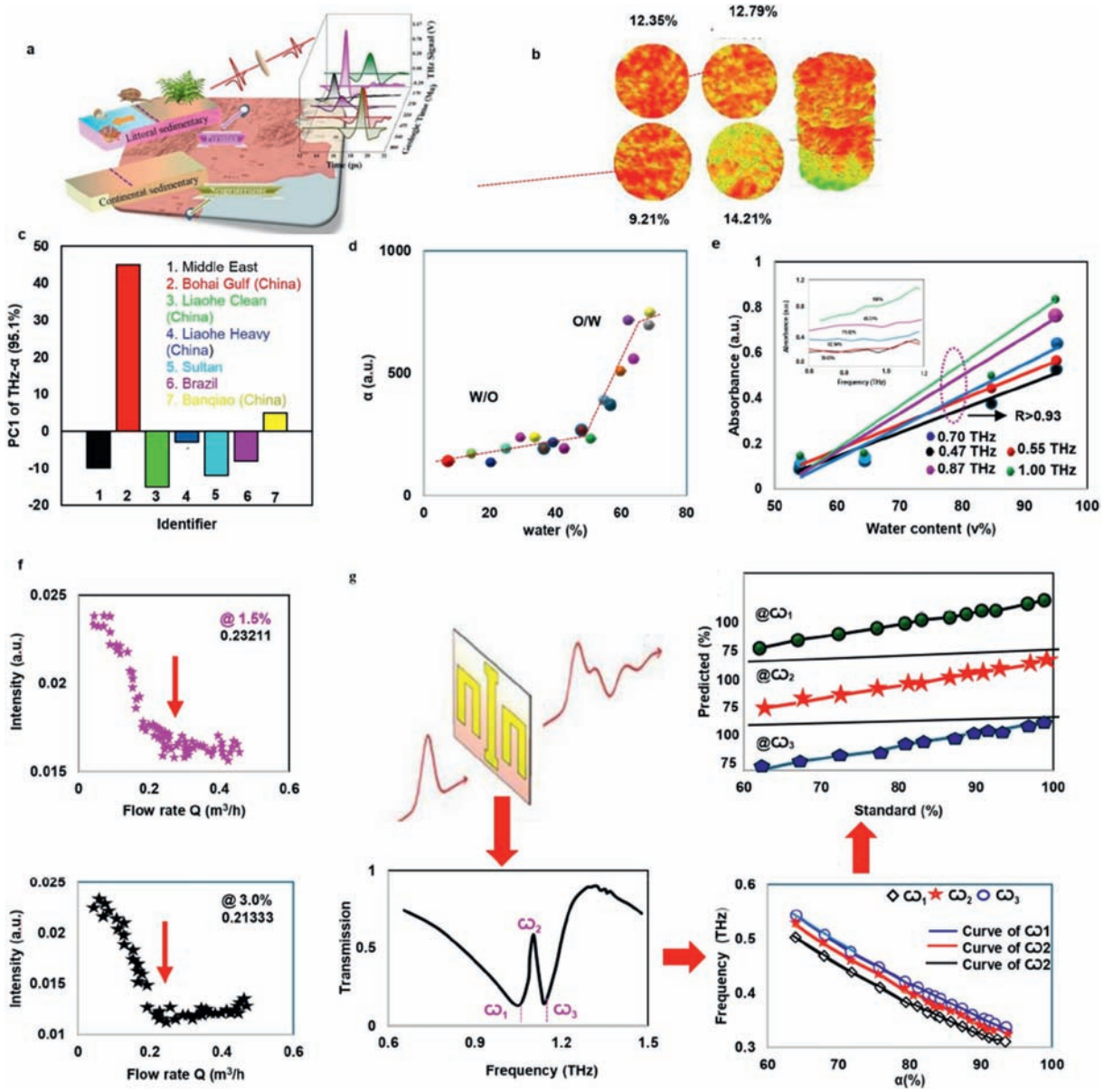


Fig. 16. THz spectroscopy applications. (a) Dating sedimentary rocks using THz (Meng et al., 2022); evaluation of (b) porosity of rock, (c) petroleum products from various oil fields (reproduced with permission of Zhan et al. (2015), Copyright 2015, Elsevier); (d) the demulsification process of crude oil emulsion; (e)–(f) moisture content of crude oil (reproduced with permission of Song et al. (2016), Copyright 2016, American Chemical Society; reproduced with permission of Song et al. (2017), Copyright 2019, American Chemical Society;, and (g) oil–water two-phase flow pattern transitions (reproduced with permission of Song et al. (2019), Copyright 2017, American Chemical Society).

models for kerogen decomposition, improving signal penetration in varied formations, and incorporating THz data into real-time monitoring systems to allow for better process control (Miao et al., 2020).

Near-critical and subcritical water technologies require detailed studies on catalytic stability, material performance under extreme conditions, and ways to sustainably recycle water. Recent researches show that while these methods improve pyrolysis reactions and hydrocarbon yields, there are still challenges in designing large-scale equipment, resisting corrosion, and assessing environmental impacts over the lifecycle (Wang and Li, 2019). Broader research should not just focus on technology-specific improvements but also on developing coupled thermo-hydro-chemical-mechanical (THCM) reservoir models, using high-resolution monitoring techniques, and conducting pilot-scale demonstrations under various geological conditions (Mehmood et al., 2026). Addressing these areas will provide the scientific and technical foundation necessary to ensure that *in situ* conversion becomes a commercially viable and environmentally responsible method for extracting oil shale.

9. Conclusion

(1) Due to the global shift toward securing alternative energy resources, oil shale has gained attention as a promising unconventional hydrocarbon reserve. Extracting shale oil without conventional surface mining is the focus of this review paper, which has explored a wide range of *in situ* conversion technologies (ICTs) and offered potentially scalable and more sustainable methods. The fundamental problem of turning solid kerogen into producible hydrocarbons deep within the reservoir is addressed by these

technologies, which range from conduction- and convection-based systems to newly developed radiant-heating methods, chemical techniques, and diagnostic tools. These technologies involve a combination of reservoir physics, chemistry, geomechanics, and thermal engineering, and each technology offers specific benefits and necessitates a unique implementation approach based on geology and economic conditions.

(2) Several conduction-based technologies use electric heating to start kerogen pyrolysis, such as ExxonMobil's Electrofrac™ and Shell's *in situ* conversion process (ICP). ICP uses electric heaters in vertical or horizontal wells, whereas Electrofrac™ transfers heat by forming conductive fractures. Although these technologies are slow and energy intensive, they offer precise control. In convection-based techniques, such as modified thermal injection (MTI) and nitrogen injection–assisted *in situ* conversion process (NAICP), heat transfer, pressure, and oil displacement are achieved by using superheated steam or nitrogen gas. Among these, NAICP stands out as particularly efficient, as it combines electric heating with nitrogen injection to improve heat transfer and lower energy usage. Radio frequency (RF) and microwave systems are radiant heating technologies that use electromagnetic radiation to heat shale formations. Their high energy consumption and limited depth penetration currently limit them to the experimental stage, despite their potential for quicker heating and cleaner products compared to other methods. The subcritical and near-critical water methods break down kerogen and extract oil using high-temperature, pressurized water; however, these chemically efficient and environmentally friendly processes have only been validated at the laboratory scale. Terahertz (THz) spectroscopy has been presented as a diagnostic technique instead of a conversion technique. An analysis of detection technologies demonstrates how NMR, TGA, and IR can support the optimization of *in situ* conversion strategies by offering crucial information about kerogen decomposition temperatures and energy consumption. THz spectroscopy offers high-resolution, real-time analysis of kerogen structure, pore evolution, and thermal behavior, allowing it to optimize other ICTs. In situ combustion technologies produce heat underground by using a portion of the shale as fuel. For example, while the TS-A method from Jilin University has exhibited high oil recovery, controlling underground combustion remains rather difficult.

(3) NAICP stands out as the most promising technology among all those listed above. It effectively enhances heat transfer, reduces energy consumption, and improves oil recovery through the synergistic use of electrical heating and nitrogen injections. In contrast, THz spectroscopy remains the least developed technology in terms of field deployment. Despite its high value as a characterization tool, its application in operational settings is still limited to the experimental and research stages. However, as more attention is paid to real-time reservoir diagnostics and efficiency optimization, THz spectroscopy may play an increasingly critical role in integrated ICT systems

(4) In summary, ICTs for oil shale include various thermal, chemical, and diagnostic methods, each of which addresses specific technical challenges. Although none of these technologies are fully ready for global commercial use, this indicates that shale oil can be extracted in a cleaner, scalable, and potentially cheaper manner than traditional surface mining. NAICP currently leads these technologies in terms of efficiency, while diagnostic techniques such as THz spectroscopy offer the potential to improve monitoring and optimization over time.

(5) In situ oil shale conversion technologies hold significant potential but require further research to move from experimental concepts toward commercial reality. Advancements in injection strategies, diagnostic tools, and water-based methods, together with robust THCM modeling and pilot-scale demonstrations, are essential for improving efficiency, ensuring sustainability, and establishing oil shale as a viable and environmentally responsible energy resource.

CRediT authorship contribution statement

Atif Zafar: Supervision, Project administration, Methodology, Data curation, Conceptualization. **Mishal Iqbal:** Writing – review & editing, Writing – original draft, Visualization, Methodology, Data curation, Conceptualization. **Yumna Sami:** Writing – review & editing, Writing – original draft, Methodology, Data curation, Conceptualization.

Declaration of competing interest

The authors declare that they have no conflicts of interest.

Abbreviation

AMS	Anisotropy of Magnetic Susceptibility
BDE	Bond Dissociation Energy
CCR	Control Convection Retorting
CEOR	Cumulative Energy-to-Oil Ratio
CRUSH	Chevron's technology for the Recovery and Upgrading of Oil from Shale
CT	Computed Tomography
ECR	Energy Conversion Ratio
EM	Early Mature
EOR	Enhance Oil Recovery
EPE	Effective Pyrolysis Energy
FTIR	Fourier Transform Infrared Spectroscopy
GC-MS	Gas Chromatography–Mass Spectrometry
GFC	Geothermic Fuel Cell
HVF	High-Voltage Power Frequency
ICFD	In situ Fracturing Chemical-Developing technology
ICP	In Situ Conversion Process
IEP	In Situ Extraction Process
IIST-VTPC	India Institute of Space Science and Technology-Vacuum Thermal Pyrolysis Chamber
IITRI	Illinois Institute of Technology Research Institute
IM	Immature (IM)
IR	Infrared
IVE	In-Situ Vapor Extraction
LETC	Laramie Energy Technology Center
LLNL	Lawarence Livermore National Laboratory
LM	Late Mature
Micro-CT	Micro-Computed Tomography
MIS	Modified In Situ
MM	Middle Mature
MTI	Modified Thermal Injection
MS	Mass Spectroscopy
MWE	Mountain West Energy
NAICP	Nitrogen-Assisted In-situ Conversion Process
NCW	Near-Critical Technology
NMR	Nuclear Magnetic Resonance
OM	Over Mature

RF	Radio Frequency
RF/CF	Radio Frequency/Critical Fluids
SCW	Super Critical Water
SEM	Scanning Electron Microscopy
Tci	First Critical Temperature
Tcf	Final Critical Temperature
TEM	Transmission Electron Microscopy
TGA	Thermogravimetry Analysis
THCM	Thermo-Hydro-Chemical-Mechanical
THz	Terahertz
THz–TDS	Terahertz-Time Domain Spectroscopy
TIS	True In Situ
TOC	Total Organic Carbon
TPH	Total Petroleum Hydrocarbons
TS	Simulated Temperatures
TS-A	Topochemical Synthesis-Air
TTA	Thermal Terahertz Analysis
TYUT	Taiyuan University of Technology
XμCT	X-ray Microcomputed Tomography
XRD	X-ray Diffraction

References

Ahmad, I., Chengwen, L., Mingxuan, W., Zhengxiao, X., Zafar, A., Li, Z., 2021. Black rice huskash is a useful template for foam stability to enhance oil recovery (EOR). Chem. Technol. Fuels Oils 56 (6), 962–970.

Al Rassas, A., Ren, S., Sun, R., Zafar, A., Moharam, S., 2020a. Numerical simulation of pressure dissipation behavior on migration patterns in hydraulically fractured in shale formation. In: Conference of the Arabian Journal of Geosciences. Springer Nature Switzerland, Cham, pp. 163–166.

Al Rassas, A., Ren, S., Sun, R., Zafar, A., Moharam, S., Guan, Z., Alalimi, A.M., Alomaisi, M., 2020b. Application of 3d reservoir geological model on Es1 formation, block Nv32, Shenvsi Oilfield, China. Open J. Yangtze Oil Gas 5 (2), 54. https://doi.org/10.4236/ojogas.2020.52006.

Al-Ayed, O.S., Suliman, M.R., Rahman, N.A., 2010. Kinetic modeling of liquid generation from oil shale in fixed bed retort. Appl. Energy 87 (7), 2273–2277. https://doi.org/10.1016/j.apenergy.2010.02.006.

Alhesan, J.S.A., Amer, M.W., Marshall, M., Jackson, W.R., Gengenbach, T., Qi, Y., Gorbaty, M.L., Cassidy, P., Chaffee, A.L., 2019. A comparison of the NaOH-HCl and HCl-HF methods of extracting kerogen from two different marine oil shales. Fuel 236, 880–889.

Allawzi, M., Al-Otoom, A., Allaboun, H., Ajlouni, A., Al Nseirat, F., 2011. CO2 supercritical fluid extraction of Jordanian oil shale utilizing different co-solvents. Fuel Process. Technol. 92 (10), 2016–2023.

Alstadt, K.N., Katti, D.R., Katti, K.S., 2012. An *in situ* FTIR step-scan photoacoustic investigation of kerogen and minerals in oil shale. Spectrochim. Acta Mol. Biomol. Spectrosc. 89, 105–113. https://doi.org/10.1016/j.saa.2011.10.078.

Aurela, M., Mylläri, F., Konist, A., Saarikoski, S., Olin, M., Simonen, P., Bloss, M., Neshumayev, D., Salo, L., Maasikmets, M., Sopila, M., Maso, M.D., Keskinen, J., Timonen, H., Rönkkö, T., 2021. Chemical and physical characterization of oil shale combustion emissions in Estonia. Atmos. Environ. X 12, 100139. https://doi.org/10.1016/j.aeaoa.2021.100139.

Bai, F.T., 2015. Theoretical and Laboratory Experimental Study on Local Chemical Pyrolysis of Oil Shale. Jilin University, p. 128.

Bai, F.T., Guo, W., Lü, X., Liu, Y., Guo, M., Li, Q., Sun, Y., 2015. Kinetic study on the pyrolysis behavior of Huadian oil shale via non-isothermal thermogravimetric data. Fuel 146, 111–118. https://doi.org/10.1016/j.fuel.2014.12.073.

Bai, F., Sun, Y., Liu, Y., Guo, M., 2017. Evaluation of the porous structure of Huadian oil shale during pyrolysis using multiple approaches. Fuel 187, 1–8. https://doi.org/10.1016/j.fuel.2016.09.012.

Bao, R., Wu, S., Zhao, K., Zheng, L., Xu, C., 2013. Applying terahertz time-domain spectroscopy to probe the evolution of kerogen in close pyrolysis systems. Sci. China Phys. Mech. Astron. 56 (8), 1603–1605. https://doi.org/10.1007/s11433-013-5085-6.

Bao, R., Miao, X., Feng, C., Zhang, Y., Zhan, H., Zhao, K., Wang, M., Yao, J., 2016. Characterizing the oil and water distribution in low permeability core by reconstruction of terahertz images. Sci. China Phys. Mech. Astron. 59 (6), 664201. https://doi.org/10.1007/s11433-016-5792-x.

Bhargava, S., Awaja, F., Subasinghe, N.D., 2005. Characterisation of some Australian oil shale using thermal, X-ray and IR techniques. Fuel 84 (6), 707–715. https://doi.org/10.1016/j.fuel.2004.11.013.

Branch, M.C., 1979. In-situ combustion retorting of oil shale. Prog. Energy Combust. Sci. 5 (3), 193–206.

Brandt, A.R., 2008. Converting oil shale to liquid fuels: energy inputs and greenhouse gas emissions of the Shell *in situ* conversion process. Environ. Sci. Technol. 42 (19), 7489–7495. https://doi.org/10.1021/es800531f.

Braun, R.L., Burnham, A.K., 1992. PMOD: a flexible model of oil and gas generation, cracking, and expulsion. Org. Geochem. 19 (1–3), 161–172. https://doi.org/10.1016/0146-6380(92)90034-U.

Britton, M.W., Martin, W.L., McDaniel, J.D., Wahl, H.A., 1981. Fracture Preheat Oil Recovery Process. No. US 4265310.

Burnham, A.K., 2017. Porosity and permeability of Green River oil shale and their changes during retorting. Fuel 203, 208–213. https://doi.org/10.1016/j.fuel.2017.04.119.

Burwell, E.L., Sterner, T.E., Carpenter, H.C., 1970. Shale oil recovery by in-situ retorting-A pilot study. J. Petrol. Technol. 22 (12), 1520–1524. https://doi.org/10.2118/2915-PA.

Burwell, E.L., Sterner, T.E., Carpenter, H.C., 1973. In Situ Retorting of Oil Shale: Results of Two Field Experiments. US Department of Interior, Bureau of Mines. No. 7781-7800.

Canoğlu, M.C., 2019. Selection of suitable dam axis location considering permeability and grout curtain optimization. Environ. Eng. Geosci. 25 (1), 15–25. https://doi.org/10.2113/EEG-2054.

Cao, X., Birdwell, J.E., Chappell, M.A., Li, Y., Pignatello, J.J., Mao, J., 2013. Characterization of oil shale, isolated kerogen, and postpyrolysis residues using advanced 13C solid-state nuclear magnetic resonance spectroscopy. AAPG (Am. Assoc. Pet. Geol.) Bull. 97 (3), 421–436.

Cha, C.Y., McCarthy, H., 1982. In-situ oil shale retorting. Oil Shale Processing Technology Center for Professional Advancement, East Brunswick, pp. 189–216.

Cheikh Moine, E., Groune, K., El Hamidi, A., Khachani, M., Halim, M., Arsalane, S., 2016. Multistep process kinetics of the non-isothermal pyrolysis of Moroccan Rif Oil Shale. Energy 115, 931–941. https://doi.org/10.1016/j.energy.2016.09.033.

Chen, M., Shi, Y., Dong, L., Wang, Q., 2010. Flash pyrolysis of Fushun oil shale fine particles in an experimental fluidized-bed reactor. Oil Shale 27 (4), 297.

Chen, Z., Tang, Y., Wang, H., Chen, Y., 2014. Comprehensive treatment of gas channeling at the later stage of CO 2 flooding. Lit. Res. 26 (5), 102–106.

Chen, B., Han, X., Jiang, X., 2016. In situ FTIR analysis of the evolution of functional groups of oil shale during pyrolysis. Energy Fuel. 30 (7), 5611–5616.

Chen, C., Gao, S., Sun, Y., Guo, W., Li, Q., 2017. Research on underground dynamic fluid pressure balance in the process of oil shale in-situ fracturing-nitrogen injection exploitation. J. Energy Resour. Technol. 139 (3), 032908.

Chen, B., Cai, J., Chen, X., Wu, D., Pan, Y., 2024. A review on oil shale in-situ mining technologies: opportunities and challenges. Oil Shale 41 (1).

Council, We, 2004. Survey of Energy Resources. World Energy Council.

Crawford, P.M., Killen, J.C., 2010. New challenges and directions in oil shale development technologies. ACS (Am. Chem. Soc.) Symp. Ser. 1032, 21–60.

Crawford, P.M., Biglarbigi, K., Dammer, A.R., Knaus, E., 2008. Advances in world oil shale production technologies. In: *SPE* Annual Technical Conference and Exhibition?. https://doi.org/10.2118/116570-MS.

Dammer, A.R., Killen, J.C., Biglarbigi, K., Crawford, P.M., Knaus, E., Johnson, H., 2007. Secure fuels from domestic resources: the continuing evolution of America's oil shale and tar sands industries. Office of Naval Petroleum and Oil Shale Reserves. Department of Energy, Washington, DC, USA.

Deng, S., Wang, Z., Gu, Q., Meng, F., Li, J., Wang, H., 2011. Extracting hydrocarbons from Huadian oil shale by sub-critical water. Fuel Process. Technol. 92 (5), 1062–1067. https://doi.org/10.1016/j.fuproc.2011.01.001.

Doğan, Ö.M., Uysal, B.Z., 1996. Non-isothermal pyrolysis kinetics of three Turkish oil shales. Fuel 75 (12), 1424–1428. https://doi.org/10.1016/0016-2361(96)00089-0.

Dong, F., Feng, Z., Yang, D., Zhao, Y., Elsworth, D., 2018. Permeability evolution of pyrolytically-fractured oil shale under *in situ* conditions. Energies 11 (11), 3033. https://doi.org/10.3390/en11113033.

Dorney, T.D., Johnson, J.L., Van Rudd, J., Baraniuk, R.G., Symes, W.W., Mittleman, D.M., 2001. Terahertz reflection imaging using Kirchhoff migration. Opt Lett. 26 (19), 1513–1515. https://doi.org/10.1364/OL.26.001513.

Dorney, T.D., Rossow, M.J., Symes, W.W., Mittleman, D.M., 2003. Single-cycle terahertz electromagnetic pulses: a new test bed for physical seismic modeling. Geophysics 68 (1), 308–313. https://doi.org/10.1190/1.1543216.

Durand, B., 2003. A history of organic geochemistry. Oil Gas Sci. Technol. 58 (2), 203–231. https://doi.org/10.2516/ogst:2003014.

Dyni, J.R., 2003. Geology and resources of some world oil-shale deposits. Oil Shale 20 (3). https://doi.org/10.3133/sir29955294.

Economides, M.J., Hill, A.D., Ehlig-Economides, C., Zhu, D., 2012. In: Petroleum Production Systems, second ed. Prentice Hall.

Eseme, E., Littke, R., Krooss, B.M., 2006. Factors controlling the thermo-mechanical deformation of oil shales: implications for compaction of mudstones and exploitation. Mar. Petrol. Geol. 23 (7), 715–734. https://doi.org/10.1016/j.marpetgeo.2006.02.007.

Eseme, E., Urai, J.L., Krooss, B.M., Littke, R., 2007. Review of mechanical properties of oil shales: implications for exploitation and basin modelling. Oil Shale 24 (2). https://doi.org/10.3176/oil.2007.2.06.

Fang, A., He, R., 2009. Design of wireless environmental monitoring data acquisition System based on cortex. In: 2009 Pacific-Asia Conference on Circuits, Communications and Systems. IEEE, pp. 78–80. https://doi.org/10.1109/PACCS.2009.188.

Fathinasab, M., Ayatollahi, S., Hemmati-Sarapardeh, A., 2015. A rigorous approach to predict nitrogen-crude oil minimum miscibility pressure of pure and nitrogen mixtures. Fluid Phase Equilib. 399, 30–39. https://doi.org/10.1016/j.fluid.2015.04.003.

Fletcher, T.H., Gillis, R., Adams, J., Hall, T., Mayne, C.L., Solum, M.S., Pugmire, R.J., 2014. Characterization of macromolecular structure elements from a Green River oil shale, II. Characterization of pyrolysis products by 13C NMR, GC/MS, and FTIR. Energy Fuel. 28 (5), 2959–2970. https://doi.org/10.1021/ef500095j.

Gao, Y., Long, Q., Su, J., He, J., Guo, P., 2016. Approaches to improving the porosity and permeability of Maoming oil shale, South China. Oil Shale 33 (3), 216.
Geng, Y., Liang, W., Liu, J., Cao, M., Kang, Z., 2017. Evolution of pore and fracture structure of oil shale under high temperature and high pressure. Energy Fuel. 31 (10), 10404–10413. https://doi.org/10.1021/acs.energyfuels.7b01071.
Greeney, N.S., Scales, J.A., 2007. Dielectric microscopy with submillimeter resolution. Appl. Phys. Lett. 91 (22). https://doi.org/10.1063/1.2818674.
Greeney, N.S., Scales, J.A., 2012. Non-contacting characterization of the electrical and mechanical properties of rocks at submillimeter scales. Appl. Phys. Lett. 100 (12). https://doi.org/10.1063/1.3692576.
Gu, J., Fu, H., Yu, D., Tang, W., Sun, Y., Guo, W., Shi, W., 2024. Pyrolysis characteristics and evolution of the organics in Nong'an oil shale lump during subcritical water extraction. Fuel 364, 131064.
Guo, S., Ruan, Z., 1995. The composition of Fushun and Maoming shale oils. Fuel 74 (11), 1719–1721. https://doi.org/10.1016/0016-2361(95)00137-T.
Guo, H., Pei, Y., Wang, K., Cheng, Q., Ding, Y., Jin, Z., Yang, Y., Wu, Q., Liu, Y., 2015. Identifying the reaction mechanism of oil-shale self-heating retorting by thermal analysis techniques. Fuel 160, 255–264. https://doi.org/10.1016/j.fuel.2015.07.106.
Guo, H., Cheng, Q., Wang, D., Jin, Z., Ding, Y., Pei, Y., Zhu, H., Liu, Y., 2016. Analyzing the contribution of semicokes to forming self-heating in the oil-shale self-heating retorting process. Energy Fuel. 30 (7), 5355–5362. https://doi.org/10.1021/acs.energyfuels.6b00351.
Guo, W., Zhang, M., Sun, Y., Li, Q., Zhao, S., Deng, S., 2020. Numerical simulation and field test of grouting in Nong'an pilot project of in-situ conversion of oil shale. J. Petrol. Sci. Eng. 184, 106477. https://doi.org/10.1016/j.petrol.2019.106477.
Han, X., Jiang, X., Cui, Z., 2009. Studies of the effect of retorting factors on the yield of shale oil for a new comprehensive utilization technology of oil shale. Appl. Energy 86 (11), 2381–2385.
Hascakir, B., Babadagli, T., Akin, S., 2008. Experimental and numerical simulation of oil recovery from oil shales by electrical heating. Energy Fuel. 22 (6), 3976–3985. https://doi.org/10.1021/ef800389v.
He, L., Ma, Y., Yue, C., Li, S., Tang, X., 2022. Microwave pyrolysis of oil shale for high-quality oil and gas production. J. Therm. Anal. Calorim. 147 (16), 9083–9093. https://doi.org/10.1007/s10973-021-11169-4.
Hillier, J.L., Fletcher, T.H., Solum, M.S., Pugmire, R.J., 2013. Characterization of macromolecular structure of pyrolysis products from a Colorado Green River oil shale. Ind. Eng. Chem. Res. 52 (44), 15522–15532. https://doi.org/10.1021/ie402070s.
Hou, X.L., 1984. Shale Oil Industry in China. Petroleum Industry Press, Beijing, p. 159.
Hou, L.H., Luo, X., Lin, S.H., Li, Y.X., Zhang, L.J., Ma, W.J., 2022. Assessment of recoverable oil and gas resources by in-situ conversion of shale—Case study of extracting the Chang 73 shale in the Ordos Basin. Pet. Sci. 19 (2), 441–458. https://doi.org/10.1016/j.petsci.2021.10.015.
Hu, S., Xiao, C., Liang, X., Cao, Y., Wang, X., Li, M., 2019. The influence of oil shale *in situ* mining on groundwater environment: a water-rock interaction study. Chemosphere 228, 384–389. https://doi.org/10.1016/j.chemosphere.2019.04.142.
Hu, S.Y., Sun, Z.X., Li, Q.Y., 2022. Environmental impacts of oil shale exploitation and research progress. J. Environ. Prot. Oil Gas Field 32 (4). http://refhub.elsevier.com/S1995-8226(23)00232-7/sref17.
Huber, A.J., Keilmann, F., Wittborn, J., Aizpurua, J., Hillenbrand, R., 2008. Terahertz near-field nanoscopy of mobile carriers in single semiconductor nanodevices. Nano Lett. 8 (11), 3766–3770. https://doi.org/10.1021/nl802086x.
Hutchinson, D.L., 1980. Geokinetics in Situ Shale Oil Recovery Project. Third Annual Report, *1979*. Geokinetics, Inc., Concord, CA (USA) (No. DOE/LETC/10787-43).
Jaber, J.O., Probert, S.D., 1999. Environmental-impact assessment for the proposed oil-shale integrated tri-generation plant. Appl. Energy 62 (3), 169–209. https://doi.org/10.1016/S0306-2619(99)00006-9.
Jagadisan, A., Heidari, Z., 2022. Molecular dynamic simulation of the impact of thermal maturity and reservoir temperature on the contact angle and wettability of kerogen. Fuel 309, 122039. https://doi.org/10.1016/j.fuel.2021.122039.
Jagodzińska, K., Lopez, C.G., Yang, W., Jönsson, P.G., Pretz, T., Raulf, K., 2021. Characterisation of excavated landfill waste fractions to evaluate the energy recovery potential using Py-GC/MS and ICP techniques. Resour. Conserv. Recycl. 168, 105446. https://doi.org/10.1016/j.resconrec.2021.105446.
Jia, J., Liu, Z., Meng, Q., Liu, R., Sun, P., Chen, Y., 2012. Quantitative evaluation of oil shale based on well log and 3-D seismic technique in the Songliao Basin, northeast China. Oil Shale 29 (2). https://doi.org/10.3176/oil.2012.2.04.
Jiang, X.M., Han, X.X., Cui, Z.G., 2007. New technology for the comprehensive utilization of Chinese oil shale resources. Energy 32 (5), 772–777. https://doi.org/10.1016/j.energy.2006.05.001.
Jin, J.M., Kim, S., Birdwell, J.E., 2012. Molecular characterization and comparison of shale oils generated by different pyrolysis methods. Energy Fuel. 26 (2), 1054–1062.
Kalu, I.E., Jossou, E., Arthur, E.K., Ja'afaru, S., Ishidi, E.Y., 2022. Characterization and mechanical property measurements by instrumented indentation testing of Niger Delta oil shale cuttings. Int. J. Eng. Res. Afr. 59, 89–100. https://doi.org/10.4028/p-2m9z7.
Kaminsky, R.D., Symington, W.A., 2008. Hydrocarbon Recovery from Impermeable Oil Shales. U.S. Patent and Trademark Office, Washington, DC. U.S. Patent No. 7,441,603.
Kang, Z.Q., Zhao, Y.S., Meng, Q.R., Yang, D., Xi, B.P., 2009. Micro-CT experimental research of oil shale thermal cracking laws. Chin. J. Geophys. 52 (3), 842–848.
Kang, Z., Yang, D., Zhao, Y., Hu, Y., 2011. Thermal cracking and corresponding permeability of Fushun oil shale. Oil Shale 28 (2), 273.
Kang, Z., Zhao, J., Yang, D., Zhao, Y., Hu, Y., 2017. Study of the evolution of micron-scale pore structure in oil shale at different temperatures. Oil Shale 34 (1).
Kang, Z., Zhao, Y., Yang, D., 2020a. Review of oil shale in-situ conversion technology. Appl. Energy 269, 115121. https://doi.org/10.1016/j.apenergy.2020.115121.
Kang, Z., Zhao, Y., Yang, D., Tian, L., Li, X., 2020b. A pilot investigation of pyrolysis from oil and gas extraction from oil shale by in-situ superheated steam injection. J. Petrol. Sci. Eng. 186, 106785.
Kang, W.L., Zhou, B.B., Issakhov, M., Gabdullin, M., 2022. Advances in enhanced oil recovery technologies for low permeability reservoirs. Pet. Sci. 19 (4), 1622–1640. https://doi.org/10.1016/j.petsci.2022.06.010.
Kar, T., Hascakir, B., 2017. In-situ kerogen extraction via combustion and pyrolysis. J. Petrol. Sci. Eng. 154, 502–512. https://doi.org/10.1016/j.petrol.2017.01.051.
Kashif, M., Cao, Y., Yuan, G., Asif, M., Jian, W., Zhukhun, W., Rehman, S.U., Zafar, A., Kamran, M., Isgandrove, O., Naz, A.F., 2019. Sedimentological impact on reservoir quality of Es1 sandstone of Shahejie formation, Nanpu Sag, East China. Arabian J. Geosci. 12 (17), 545. https://doi.org/10.1007/s12517-019-4671-y.
Khalil, A.M., 2013. Oil shale pyrolysis and effect of particle size on the composition of shale oil. Oil Shale 30 (2), 136. https://doi.org/10.3176/oil.2013.2.04.
Kibodeaux, K.R., 2014. Evolution of porosity, permeability, and fluid saturations during thermal conversion of oil shale. In: SPE Annual Technical Conference and Exhibition?. http://refhub.elsevier.com/S0920-4105(18)30646-6/sref14.
Kok, M.V., Bagci, S., 2010. An investigation of the applicability of the in-situ thermal recovery technique to the Beypazari oil shale. Energy Sources, Part A Recovery, Util. Environ. Eff. 33 (3), 183–193. https://doi.org/10.1080/15567030801907387.
Kök, M., Guner, G., Bagci, S., 2008. Laboratory steam injection applications for oil shale fields of Turkey. Oil Shale 25 (1).
Korb, J.P., Nicot, B., Louis-Joseph, A., Bubici, S., Ferrante, G., 2014. Dynamics and wettability of oil and water in oil shales. J. Phys. Chem. C 118 (40), 23212–23218.
Lan, X., Luo, W., Song, Y., Zhou, J., Zhang, Q., 2015. Effect of the temperature on the characteristics of retorting products obtained by Yaojie oil shale pyrolysis. Energy Fuel. 29 (12).
Le Doan, T.V., Bostrom, N.W., Burnham, A.K., Kleinberg, R.L., Pomerantz, A.E., Allix, P., 2013. Green River oil shale pyrolysis: Semi-open conditions. Energy Fuel. 27 (11), 6447–6459. https://doi.org/10.1021/ef401162p.
Lee, K.J., Moridis, G.J., Ehlig-Economides, C.A., 2017. Numerical simulation of diverse thermal *in situ* upgrading processes for the hydrocarbon production from kerogen in oil shale reservoirs. Energy Explor. Exploit. 35 (3), 315–337. https://doi.org/10.1177/0144598716689354.
Li, S., Yue, C., 2003. Study of pyrolysis kinetics of oil shale. Fuel 82 (3), 337–342.
Li, X., Zhou, H., Wang, Y., Qian, Y., Yang, S., 2015. Thermoeconomic analysis of oil shale retorting processes with gas or solid heat carrier. Energy 87, 605–614. https://doi.org/10.1016/j.energy.2015.05.045.
Lin, Y., Liao, Y., Yu, Z., Fang, S., Lin, Y., Fan, Y., Peng, X., Ma, X., 2016. Co-pyrolysis kinetics of sewage sludge and oil shale thermal decomposition using TGA–FTIR analysis. Energy Convers. Manag. 118, 345–352. https://doi.org/10.1016/j.enconman.2016.04.004.
Liu, Z.Y., 2019. Coupled Numerical Simulation of In-Situ Oil Shale Exploitation. Jilin University, pp. 125–133 (in Chinese).
Liu, Z., Meng, Q., Dong, Q., Zhu, J., Guo, W., 2003. The situation of oil resources in China. J. Earth Sci. 193–252.
Liu, D.X., Wang, H.Y., Zheng, D.W., Fang, C.H., Ge, Z.X., 2009. World progress of oil shale in-situ exploitation methods. Nat. Gas. Ind. 29 (5), 128–132.
Liu, Z., Meng, Q., Dong, Q., Zhu, J., Guo, W., Ye, S., Jia, J., 2017. Characteristics and resource potential of oil shale in China. Oil Shale 34 (1).
Liu, Z., Sun, Y., Guo, W., Li, Q., 2020. Sealing effects of marginal gas injection on oil shale *in situ* pyrolysis exploitation. J. Petrol. Sci. Eng. 189, 106968.
Liu, X., Zhao, K., Miao, X., Zhan, H., 2023. Characterization and evaluation of oil shale based on terahertz spectroscopy: a review. Energy Rev. 2 (4), 100041. https://doi.org/10.1016/j.enrev.2023.100041.
Lu, Z., Zhao, X., Liu, Z., Liu, Q., 2019. Mutual influences between organic matter and minerals during oil shale pyrolysis. Energy Fuel. 33 (3), 1850–1858. https://doi.org/10.1021/acs.energyfuels.8b03703.
Ma, Y., Huang, M., Ryu, S., Bark, C.W., Eom, C.B., Irvin, P., Levy, J., 2013. Broadband terahertz generation and detection at 10 nm scale. Nano Lett. 13 (6), 2884–2888. https://doi.org/10.1021/nl401219v.
Ma, J.X., Xue, L.F., Zhao, J.M., Bai, F.T., 2019. Numerical simulation and design optimization of temperature field of oil shale *in situ* pyrolysis and exploitation. Sci. Technol. Eng. 19 (5), 94–103.
Ma, J., Kang, D., Wang, X., Zhao, Y.P., 2022. Defining kerogen maturity from orbital hybridization by machine learning. Fuel 310, 122250. https://doi.org/10.1016/j.fuel.2021.122250.
Martemyanov, S., Bukharkin, A., Koryashov, I., Ivanov, A., 2016. Analysis of applicability of oil shale for *in situ* conversion. In: AIP Conference Proceedings. AIP Publishing LLC, 020001.
Martins, M.F., Salvador, S., Thovert, J.F., Debenest, G., 2010. Co-current combustion of oil shale–part 1: characterization of the solid and gaseous products. Fuel 89 (1), 144–151. https://doi.org/10.1016/j.fuel.2009.06.036.
Mehmani, Y., Burnham, A.K., Tchelepi, H.A., 2016. From optics to upscaled thermal conductivity: green River oil shale. Fuel 183, 489–500. https://doi.org/10.1016/j.fuel.2016.06.101.

Mehmood, A., Chen, Z., Zafar, A., Zhu, C.Y., Zhang, T., Gong, L., Li, Y., 2026. Numerical study on the heat recovery of fractured rock under thermal-hydraulic coupling. Int. J. Heat Mass Tran. 255, 127734. https://doi.org/10.1016/j.ijheatmasstransfer.2025.127734.

Meng, Z., Zhan, H., Chen, R., Miao, X., Zhao, K., 2022. Terahertz dating of sedimentary rocks. Front. Phys. 10, 838275. https://doi.org/10.3389/fphy.2022.838275.

Miao, X., Li, H., Bao, R., Feng, C., Wu, H., Zhan, H., Li, Y., Zhao, K., 2017a. Discriminating the mineralogical composition in drill cuttings based on absorption spectra in the terahertz range. Appl. Spectrosc. 71 (2), 186–193. https://doi.org/10.1177/0003702816653129.

Miao, X., Zhan, H., Zhao, K., 2017b. Application of THz technology in oil and gas optics. Sci. China Phys. Mech. Astron. 60 (2), 024231. https://doi.org/10.1007/s11433-016-0452-9.

Miao, X., Zhu, J., Zhao, K., Zhan, H., Yue, W., 2018. Determining the humidity-dependent ortho-to-para ratio of water vapor at room temperature using terahertz spectroscopy. Appl. Spectrosc. 72 (7), 1040–1046. https://doi.org/10.1177/0003702818772853.

Miao, X., Chen, M., Li, Y., Zhan, H., Zhao, K., Yue, W., 2020. Simultaneous determination of organic distribution and content in oil shale by terahertz imaging. Energy Fuel. 34 (2), 1664–1668. https://doi.org/10.1021/acs.energyfuels.9b04038.

Mogensen, K., Xu, S., 2020. Comparison of three miscible injectants for a high-temperature, volatile oil reservoir-with particular emphasis on nitrogen injection. J. Petrol. Sci. Eng. 195, 107616. https://doi.org/10.1016/j.petrol.2020.107616.

Mokhlisse, A., Chanâa, M.B., Outzourhit, A., 2000. Pyrolysis of the Moroccan (Tarfaya) oil shales under microwave irradiation. Fuel 79 (7), 733–742. https://doi.org/10.1016/S0016-2361(99)00209-4.

Nimblett, J., Ruppel, C., 2003. Permeability evolution during the formation of gas hydrates in marine sediments. J. Geophys. Res. Solid Earth 108 (B9).

Noble, R.D., Harris, H.G., Tucker, W.F., 1981. Isothermal oil shale pyrolysis. 2. Kinetics of product formation and composition at various pressures. Fuel 60 (7), 573–576.

Nottenburg, R., Rajeshwar, K., Rosenvold, R., DuBow, 1978. Measurement of thermal conductivity of Green River oil shales by a thermal comparator technique. Fuel 57, 789–795.

Pan, L., Dai, F., Huang, J., Liu, S., Li, G., 2016. Study of the effect of mineral matters on the thermal decomposition of Jimsar oil shale using TG–MS. Thermochim. Acta 627, 31–38. https://doi.org/10.1016/j.tca.2016.01.013.

Panahi, H., Kobchenko, M., Renard, F., Mazzini, A., Scheibert, J., Dysthe, D., Jamtveit, B., Malthe-Sorenssen, A., Meakin, P., 2013. A 4D synchrotron X-ray-tomography study of the formation of hydrocarbon-migration pathways in heated organic-rich shale. SPE J. 18 (2), 366–377.

Pei, S., Wang, Y., Zhang, L., Huang, L., Cui, G., Zhang, P., Ren, S., 2018. An innovative nitrogen injection assisted in-situ conversion process for oil shale recovery: mechanism and reservoir simulation study. J. Petrol. Sci. Eng. 171, 507–515. https://doi.org/10.1016/j.petrol.2018.07.071.

Persoff, P., 1980. Control Strategies for Abandoned In-Situ Oil Shale Retorts (LBL-14468, UC-91). Lawrence Berkeley National Laboratory. https://escholarship.org/uc/item/961516gg.

Prats, M., Closmann, P.J., Ireson, A.T., Drinkard, G., 1977. Soluble-salt processes for in-situ recovery of hydrocarbons from oil shale. J. Petrol. Technol. 29 (9), 1078–1088. https://doi.org/10.2118/6068-PA.

Qian, J.L., Yin, L., Wang, J.Q., Li, S.Y., Han, F., He, Y.G., 2011. Oil shale-supplementary Energy of Petroleum. China Petrochemical Press, Beijing (In Chinese).

Qin, F., Chen, R., Li, Y., Meng, Z., Chen, S., Zhao, K., Miao, X., Xiang, W., Yue, W., Zhan, H., 2021. Thermal terahertz analysis for the detection of trace organic matter. Energy Fuel. 35 (5), 4075–4080. https://doi.org/10.1021/acs.energyfuels.0c04354.

Qing, W., Hongpeng, L., Baizhong, S., Shaohua, L., 2009. Study on pyrolysis characteristics of huadian oil shale with isoconversional method. Oil Shale 26 (2).

Qing, W., Xinmin, W., Shuo, P., 2022. Study on the structure, pyrolysis kinetics, gas release, reaction mechanism, and pathways of Fushun oil shale and kerogen in China. Fuel Process. Technol. 225, 107058. https://doi.org/10.1016/j.fuproc.2021.107058.

Rabbani, A., Baychev, T.G., Ayatollahi, S., Jivkov, A.P., 2017. Evolution of pore-scale morphology of oil shale during pyrolysis: a quantitative analysis. Transport Porous Media 119 (1), 143–162. https://doi.org/10.1007/s11242-017-0877-1.

Rafi, J.Y., Stille, H., 2015. Basic mechanism of elastic jacking and impact of fracture aperture change on grout spread, transmissivity and penetrability. Tunn. Undergr. Space Technol. 49, 174–187. https://doi.org/10.1016/j.tust.2015.04.002.

Raukas, A., Punning, J.M., 2009. Environmental problems in the Estonian oil shale industry. Energy Environ. Sci. 2 (7), 723–728. https://doi.org/10.1039/B819315K.

Razvigorova, M., Budinova, T., Petrova, B., Tsyntsarski, B., Ekinci, E., Ferhat, M.F., 2008. Steam pyrolysis of bulgarian oil shale kerogen. Oil Shale 25 (1).

Riley, M., Redo-Sanchez, A., Karampourniotis, P., Plawsky, J., Lu, T.M., 2012. Nanostructured porous silicon films for terahertz optics. Nanotechnology 23 (32), 325301.

Routson, R.C., Wildung, R.E., Bean, R.M., 1979. A review of the environmental impact of ground disposal of oil shale wastes. J. Environ. Qual. 8 (1), 14–19.

Ryan, R.C., Fowler, T.D., Beer, G.L., Nair, V., 2010. Shell's *in situ* conversion process–from laboratory to field pilots. In: Oil Shale: a Solution to the Liquid Fuel Dilemma. American Chemical Society, pp. 161–183. https://doi.org/10.1021/bk-2010-1032.ch009.

Saif, T., Lin, Q., Singh, K., Bijeljic, B., Blunt, M.J., 2016. Dynamic imaging of oil shale pyrolysis using synchrotron X-ray microtomography. Geophys. Res. Lett. 43 (13), 6799–6807.

Saif, T., Lin, Q., Bijeljic, B., Blunt, M.J., 2017a. Microstructural imaging and characterization of oil shale before and after pyrolysis. Fuel 197, 562–574. https://doi.org/10.1016/j.fuel.2017.02.030.

Saif, T., Lin, Q., Butcher, A.R., Bijeljic, B., Blunt, M.J., 2017b. Multi-scale multi-dimensional microstructure imaging of oil shale pyrolysis using X-ray micro-tomography, automated ultra-high resolution SEM, MAPS Mineralogy and FIB-SEM. Appl. Energy 202, 628–647. https://doi.org/10.1016/j.apenergy.2017.05.039.

Saif, T., Lin, Q., Gao, Y., Al-Khulaifi, Y., Marone, F., Hollis, D., Blunt, M., Bijeljic, B., 2019. 4D *in situ* synchrotron X-ray tomographic microscopy and laser-based heating study of oil shale pyrolysis. Appl. Energy 235, 1468–1475. https://doi.org/10.1016/j.apenergy.2018.11.044.

Sanjuan, F., Aubourg, C., Saur, H., Fasentieux, B., Bernier, M., 2022. Terahertz dielectric permittivity anisotropy and fabric of oil shales: Comparison to acoustic, magnetic susceptibility, and X-ray microtomography results. Energy Fuel. 36 (20), 12555–12562. https://doi.org/10.1021/acs.energyfuels.2c02557.

Schwerdtfeger, M., Castro-Camus, E., Krügener, K., Viöl, W., Koch, M., 2013. Beating the wavelength limit. Appl. Opt. https://doi.org/10.1364/AO.52.000375.

Shi, Y., Li, S., Ma, Y., Yue, C., Shang, W., Hu, H., He, J., 2012. Pyrolysis of yaojie oil shale in a sanjiangtype pilot-scale retort. Oil Shale 29 (4).

Solum, M.S., Mayne, C.L., Orendt, A.M., Pugmire, R.J., Adams, J., Fletcher, T.H., 2014. Characterization of macromolecular structure elements from a Green River oil shale, I. Extracts. Energy Fuel. 28 (1), 453–465. https://doi.org/10.1021/ef401918u.

Song, Y., Zhan, H.L., Zhao, K., Miao, X.Y., Lu, Z.Q., Bao, R.M., Zhu, J., Xiao, L.Z., 2016. Simultaneous characterization of water content and distribution in high-water-cut crude oil. Energy Fuel. 30 (5), 3929–3933. https://doi.org/10.1021/acs.energyfuels.6b00340.

Song, Y., Miao, X., Zhao, K., Zhan, H., Jiang, C., Wang, D., Xiao, L., 2017. Reliable evaluation of oil–water two-phase flow using a method based on terahertz time-domain spectroscopy. Energy Fuel. 31 (3), 2765–2770. https://doi.org/10.1021/acs.energyfuels.7b00057.

Song, Y., Zhan, H., Jiang, C., Zhao, K., Zhu, J., Chen, R., Hao, S., Yue, W., 2019. High water content prediction of oil–water emulsions based on terahertz electromagnetically induced transparency-like metamaterial. ACS Omega 4 (1), 1810–1815. https://doi.org/10.1021/acsomega.8b02802.

Su, K., Shen, Y.C., Zeitler, J.A., 2014. Terahertz sensor for non-contact thickness and quality measurement of automobile paints of varying complexity. IEEE Trans. Terahertz Sci. Technol. 4 (4), 432–439. https://doi.org/10.1109/TTHZ.2014.2325393.

Su, Y.L., Fu, J.G., Li, L., Wang, W.D., Zafar, A., Zhang, M., Ouyang, W.P., 2020. A new model for predicting irreducible water saturation in tight gas reservoirs. Pet. Sci. 17 (4), 1087–1100. https://doi.org/10.1007/s12182-020-00429-x.

Sun, Y.H., Deng, S.H., Guo, W., Li, Q., Liu, S.C., Jia, R., 2017. In situ pyrolysis technology and pilot test project of oil shale. In: The Drilling Engineering Symposium of Drilling Engineering Professional Committee of China Coal Society.

Sun, Y., Liu, Z., Li, Q., Deng, S., Guo, W., 2019a. Controlling groundwater infiltration by gas flooding for oil shale *in situ* pyrolysis exploitation. J. Petrol. Sci. Eng. 179, 444–454. https://doi.org/10.1016/j.petrol.2019.04.055.

Sun, Y., Kang, S., Wang, S., He, L., Guo, W., Li, Q., Deng, S., 2019b. Subcritical water extraction of Huadian oil shale at 300 C. Energy Fuel. 33 (3), 2106–2114.

Sun, Y., Guo, W., Deng, S., 2021. Current situation and development trend of underground in-situ transformation and drilling and production technology of oil shale. Drill. Eng. 48 (1), 57–67.

Sun, Q.H., Wang, W.D., Su, Y.L., 2022. Production characteristics of micro-pore oil during imbibition of fracturing fluid in shale reservoir. Cent. S. Univ. 78 (6), 1.

Symington, W.A., Olgaard, D.L., Otten, G.A., Phillips, T.C., Thomas, M.M., Yeakel, J.D., 2010. ExxonMobil's Electrofrac process for *in situ* oil shale conversion. ACS (Am. Chem. Soc.) Symp. Ser. 1032.

Taber, J.J., Martin, F.D., Seright, R.S., 1997. EOR screening criteria revisited—Part 1: introduction to screening criteria and enhanced recovery field projects. SPE Reserv. Eng. 12 (3), 189–198. https://doi.org/10.2118/35385-PA.

Tahir, M.U., Liu, W.D., Zhou, H., Memon, A., Ansari, U., Akbar, I., Zafar, A., Shaikh, A., Kashif, M., Urinov, A., 2020a. A review study on micro fluid chips for enhancing the oil recovery by injecting the chemical floods. Therm. Sci. 24 (Suppl. 1), 423–432.

Tahir, M.U., Liu, W.D., Memon, A., Zhou, H., Liu, W., Zafar, A., Ansari, U., Zhu, R., 2020b. Simulating the strategies of oil field development for enhanced oil recovery. Therm. Sci. 24 (Suppl. 1), 411–422.

Tanaka, P.L., Yeakel, J.D., Symington, W.A., Spiecker, P.M., Del Pico, M., Thomas, M.M., Stone, M.T., 2011. Plan to test ExxonMobil's *in situ* oil shale technology on a proposed RD&D lease. In: 31st Oil Shale Symposium, pp. 17–19.

Tao, S., Tang, D., Xu, H., Liang, J., Shi, X., 2013. Organic geochemistry and elements distribution in Dahuangshan oil shale, southern Junggar Basin: origin of organic matter and depositional environment. Int. J. Coal Geol. 115, 41–51. https://doi.org/10.1016/j.coal.2013.05.004.

Thana'Ani, N.A.A., Mustapha, K.A., Idris, M., 2022. Source rock pyrolysis and bulk kinetic modelling of Miocene sedimentary sequences in southeastern Sabah,

Malaysia: the variability of thermal maturity to oil-gas producing kerogen. J. Petrol. Sci. Eng. 208, 109513. https://doi.org/10.1016/j.petrol.2021.109513.
Thoram, S., Ehlig-Economides, C., 2011. Heat transfer applications for the stimulated reservoir volume. In: SPE Annual Technical Conference and Exhibition.
Tiwari, P., Deo, M., Lin, C.L., Miller, J.D., 2013. Characterization of oil shale pore structure before and after pyrolysis by using X-ray micro CT. Fuel 107, 547–554. https://doi.org/10.1016/j.fuel.2013.01.006.
Vega Riveros, G., Barrios, H., 2011. Steam injection experiences in heavy and extra-heavy oil fields, Venezuela. In: SPE International Heavy Oil Conference and Exhibition. https://doi.org/10.2118/150283-MS.
Vinegar, Harold J., 2006. Shell's in-situ conversion process. In: 26th Oil Shale Symposium. Golden, Colorado.
Wang, L., Li, Z., 2019. An overview of in-situ development technology of oil shale with near and sub-critical water. IOP Conf. Ser. Earth Environ. Sci. 295 (4), 042105. https://doi.org/10.1088/1755-1315/295/4/042105. IOP Publishing.
Wang, C.C., Noble, R.D., 1983. Composition and kinetics of oil generation from non-isothermal oil shale retorting. Fuel 62 (5), 529–533. https://doi.org/10.1016/0016-2361(83)90221-1.
Wang, S., Jiang, X., Han, X., Tong, J., 2012. Investigation of Chinese oil shale resources comprehensive utilization performance. Energy 42 (1), 224–232. https://doi.org/10.1016/j.energy.2012.03.066.
Wang, Y., Wang, Y., Meng, X., Su, J., Li, F., Li, Z., 2013. US oil shale in-situ mining technology and enlightenment. Petrol. Drill. Prod. Technol. 35 (6), 55–59. https://doi.org/10.13639/j.odpt.2013.06.032.
Wang, Y., Wang, Y., Meng, X., Su, J., Long, Q., Gao, Y., 2014a. A new idea for in-situ retorting oil shale by way of fluid heating technology. Oil Drill & Prod Technol. 36 (4), 71–74.
Wang, W., Li, S.Y., Li, L.Y., Ma, Y., Yue, C.T., He, J.L., 2014b. Pyrolysis kinetics of North-Korean oil shale. Oil Shale 31 (3), 250. https://doi.org/10.3176/oil.2014.3.05.
Wang, Z., Deng, S., Gu, Q., Cui, X., Zhang, Y., Wang, H., 2014c. Subcritical water extraction of Huadian oil shale under isothermal condition and pyrolysate analysis. Energy Fuel. 28 (4), 2305–2313.
Wang, G., Yang, D., Kang, Z., Zhao, J., 2018a. Anisotropy in thermal recovery of oil shale—Part 1: thermal conductivity, wave velocity and crack propagation. Energies 11 (1), 77.
Wang, L., Yang, D., Li, X., Zhao, J., Wang, G., Zhao, Y., 2018b. Macro and meso characteristics of in-situ oil shale pyrolysis using superheated steam. Energies 11 (9), 2297. https://doi.org/10.3390/en11092297.
Wang, L., Yang, D., Zhao, J., Zhao, Y., Kang, Z., 2018c. Changes in oil shale characteristics during simulated in-situ pyrolysis in superheated steam. Oil Shale 35 (3). https://doi.org/10.3176/oil.2018.3.03.
Wang, Q., Pan, S., Bai, J., Chi, M., Cui, D., Wang, Z., Liu, Q., Xu, F., Xu, F., 2018d. Experimental and dynamics simulation studies of the molecular modeling and reactivity of the Yaojie oil shale kerogen. Fuel 230, 319–330.
Wang, Q., Ma, Y., Li, S., Hou, J., Shi, J., 2018e. Exergetic life cycle assessment of Fushun-type shale oil production process. Energy Convers. Manag. 164, 508–517. https://doi.org/10.1016/j.enconman.2018.03.013.
Wang, H., Su, Y., Wang, W., Sheng, G., Li, H., Zafar, A., 2019a. Enhanced water flow and apparent viscosity model considering wettability and shape effects. Fuel 253, 1351–1360. https://doi.org/10.1016/j.fuel.2019.05.098.
Wang, G., Yang, D., Zhao, Y., Kang, Z., Zhao, J., Huang, X., 2019b. Experimental investigation on anisotropic permeability and its relationship with anisotropic thermal cracking of oil shale under high temperature and triaxial stress. Appl. Therm. Eng. 146, 718–725. https://doi.org/10.1016/j.applthermaleng.2018.10.005.
Wang, L., Zhao, Y., Yang, D., Kang, Z., Zhao, J., 2019c. Effect of pyrolysis on oil shale using superheated steam: a case study on the Fushun oil shale, China. Fuel 253, 1490–1498. https://doi.org/10.1016/j.fuel.2019.05.134.
Wang, W., Guo, X., Duan, P., Kang, B., Zheng, D., Zafar, A., 2023. Investigation of plugging performance and enhanced oil recovery of multi-scale polymer microspheres in low-permeability reservoirs. Nat. Gas. Ind. B 10 (3), 223–232. https://doi.org/10.1016/j.ngib.2023.04.001.
Wang, L., Gao, C.H., Xiong, R.Y., Zhang, X.J., Guo, J.X., 2024. Development review and the prospect of oil shale in-situ catalysis conversion technology. Pet. Sci. 21 (2), 1385–1395. https://doi.org/10.1016/j.petsci.2023.08.035.
Wright, R., Shin, H., Trentmann, F., 2013. In: From World Power Conference to World Energy Council. World Energy Council.
Xi, Y., Li, J., Lian, W., Fu, H., Qi, Y., Tian, Y., 2023. Research on the pore evolution of oil shale under different thermal treatment temperatures using NMR and FE-SEM methods. Geofluids 2023 (1), 6101374. https://doi.org/10.1155/2023/6101374.
Xie, L., Yao, Y., Ying, Y., 2014. The application of terahertz spectroscopy to protein detection: a review. Appl. Spectrosc. Rev. 49 (6), 448–461. https://doi.org/10.1080/05704928.2013.847845.
Xie, H., Liu, T., Gao, M., Chen, L., Zhou, H., Ju, Y., Gao, F., Peng, X., Li, X., Peng, R., Gao, Y., Li, C., He, Z., Yang, M., Zhao, Z., 2021. Research on in-situ condition preserved coring and testing systems. Pet. Sci. 18 (6), 1840–1859. https://doi.org/10.1016/j.petsci.2021.11.003.
Yang, Y., Xue, J., Huang, Q., 2014. Studies on the solidification mechanisms of Ni and Cd in cement clinker during cement kiln co-processing of hazardous wastes. Constr. Build. Mater. 57, 138–143. https://doi.org/10.1016/j.conbuildmat.2013.12.081.
Yang, L., Yang, D., Zhao, J., Liu, Z., Kang, Z., 2016a. Changes of oil shale pore structure and permeability at different temperatures. Oil Shale 33 (2), 101.
Yang, Q., Qian, Y., Kraslawski, A., Zhou, H., Yang, S., 2016b. Advanced exergy analysis of an oil shale retorting process. Appl. Energy 165, 405–415. https://doi.org/10.1016/j.apenergy.2015.12.104.
Yang, Z., Zhu, J., Li, X., Luo, D., Qi, S., Jia, M., 2017. Experimental investigation of the transformation of oil shale with fracturing fluids under microwave heating in the presence of nanoparticles. Energy Fuel. 31 (10), 10348–10357. https://doi.org/10.1021/acs.energyfuels.7b00908.
Yang, Y., Wang, Q., Lu, X., Li, J., Liu, Z., 2018. Combustion behaviors and pollutant emission characteristics of low calorific oil shale and its semi-coke in a lab-scale fluidized bed combustor. Appl. Energy 211, 631–638. https://doi.org/10.1016/j.apenergy.2017.10.071.
Yang, D., Wang, L., Zhao, Y., Kang, Z., 2021. Investigating pilot test of oil shale pyrolysis and oil and gas upgrading by water vapor injection. J. Petrol. Sci. Eng. 196, 108101. https://doi.org/10.1016/j.petrol.2020.108101.
Yasir, M., Hui, S., Rahman, S.U., Ilyas, M., Zafar, A., Mehmood, A., 2020a. Estimation of land surface temperature using LANDSAT-8 data-A case study of district Malakand, Khyber Pakhtunkhwa, Pakistan. J. Liber. Art. Human. 1, 140–148.
Yasir, M., Hui, S., Zafar, A., et al., 2020b. Landuse land and landcover change detection using GIS and RS technology: a study of district Charsadda, Pakistan (1998-2018). In: 1st International Conference on Emerging Trends in Information and Engineering Technology, Jamshoro, Pakistan.
Yörük, C.R., Uibu, M., Usta, M.C., Kaljuvee, T., Trikkel, A., 2020. CO_2 mineralization by burnt oil shale and cement bypass dust: effect of operating temperature and pre-treatment. J. Therm. Anal. Calorim. 142 (2), 991–999. https://doi.org/10.1007/s10973-020-09349-9.
You, Y., Wang, X., Han, X., Jiang, X., 2019. Kerogen pyrolysis model based on its chemical structure for predicting product evolution. Fuel 246, 149–159. https://doi.org/10.1016/j.fuel.2019.02.075.
Youtsos, M.S.K., Mastorakos, E., Cant, R.S., 2013. Numerical simulation of thermal and reaction fronts for oil shale upgrading. Chem. Eng. Sci. 94, 200–213.
Yuncong, G.A.O., Mifu, Z.H.A.O., Jianbo, W.A.N.G., Chang, Z.O.N.G., 2014. Performance and gas breakthrough during CO2 immiscible flooding in ultra-low permeability reservoirs. Petrol. Explor. Dev. 41 (1), 88–95.
Zafar, A., Su, Y., Wang, W., Kashif, M., Mehmood, A., Alam, S.G., 2020a. Evaluation of the porosity and permeability of oil shale during in-situ conversion process through numerical simulation and mathematical modeling. Oil Shale 2020 (4). https://doi.org/10.3176/oil.2020.4.05.
Zafar, A., Su, Y., Wang, W., Alam, S.G., Khan, D., Yasir, M., Alrassas, A., Ahmad, I., 2020b. Heat dissipation modeling of in-situ conversion process of oil shale. Open J. Yangtze Oil Gas 5 (2), 46. https://doi.org/10.4236/ojogas.2020.52005.
Zafar, A., Su, Y.L., Li, L., Fu, J.G., Mehmood, A., Ouyang, W.P., Zhang, M., 2020c. Tight gas production model considering TPG as a function of pore pressure, permeability and water saturation. Pet. Sci. 17 (5), 1356–1369. https://doi.org/10.1007/s12182-020-00430-4.
Zafar, A., Su, Y., Wang, W., Alrassas, A., 2020d. A new correlation between cumulative hydrocarbon production time and heater spacing of in situ conversion process of oil shale. In: Conference of the Arabian Journal of Geosciences. Springer Nature Switzerland, pp. 173–175. https://doi.org/10.1007/978-3-031-43807-3_3 7.
Zafar, A., Su, Y., Li, L., Mehmood, A., Wang, H., Fu, J., 2021. The numerical simulation and wellbore modelling of steam injection and stored heat recovery from light oil reservoir. Energy Sources, Part A Recovery, Util. Environ. Eff. 43 (1), 1–16. https://doi.org/10.1080/15567036.2019.1676331.
Zafar, A., Su, Y., Wang, W., Li, L., Alam, S.G., Mehmood, A., Tahir, U., Fu, J., 2022. The numerical simulation of effects of porosity, permeability and fluid saturation on heat dissipation in an oil reservoir. In: Conference of the Arabian Journal of Geosciences. Cham:Springer International Publishing, pp. 425–428.
Zhan, H., Wu, S., Bao, R., Ge, L., Zhao, K., 2015. Qualitative identification of crude oils from different oil fields using terahertz time-domain spectroscopy. Fuel 143, 189–193. https://doi.org/10.1016/j.fuel.2014.11.047.
Zhan, H., Chen, M., Zhang, Y., Chen, R., Zhao, K., Yue, W., 2020a. Utilization of oil shale as an electromagnetic wave absorbing material in the terahertz range. IEEE Access 8, 46795–46801. https://doi.org/10.1109/ACCESS.2020.2978524.
Zhan, H., Wang, Y., Chen, M., Chen, R., Zhao, K., Yue, W., 2020b. An optical mechanism for detecting the whole pyrolysis process of oil shale. Energy 190, 116343. https://doi.org/10.1016/j.energy.2019.116343.
Zhang, T., 2009. Schlumberger acquired new technologies for RF/CF shale mining. Foreign Oil Field Eng. 25 (1), 46.
Zhang, X.Q., Li, Y.S., 2017. Changes in shale oil composition and yield after bioleaching by bacillus mucilaginosus and thiobacillus ferrooxidans. Oil Shale 34 (2).
Zhang, F., Parker, J.C., 2010. An efficient modeling approach to simulate heat transfer rate between fracture and matrix regions for oil shale retorting. Transport Porous Media 84 (1), 229–240.
Zhang, M., Wang, C., Wang, K., Han, Z., Bello, S.S., Guan, G., Abudula, A., Xu, G., 2020. Gentle hydrotreatment of shale oil in fixed bed over Ni-Mo/Al2O3 for upgrading. Fuel 281, 118495. https://doi.org/10.1016/j.fuel.2020.118495.
Zhang, C., Zhang, Q., Wang, W., Xie, Q., Su, Y., Zafar, A., 2022. Capillary and viscous forces during CO2 flooding in tight reservoirs. Capillarity 5 (6), 105–114. https://doi.org/10.46690/capi.2022.06.01.
Zhang, Z., Xie, Z., Montilla, M.J.B., Li, Y., Xu, T., Li, S., Li, X., 2024. Feasibility and recovery efficiency of in-situ shale oil conversion in fractured reservoirs via steam heating: based on a coupled thermo-flow-chemical model. J. Anal. Appl. Pyrolysis 183, 106787. https://doi.org/10.1016/j.jaap.2024.106787.
Zhao, Y., 2004. Computation of complex turbulent flow using matrix-free implicit dual time-stepping scheme and LRN turbulence model on unstructured grids.

Comput. Fluid 33 (1), 119–136. https://doi.org/10.1016/S0045-7930(03)00031-8.
Zhao, J., 2016. Method and process for extracting shale oil and gas by fracturing and chemical retorting in oil shale in-situ vertical well. U.S. Patent Appl. 14/787, 732.
Zhao, Y., Feng, Z., Yang, D., Liu, S., Sun, K., Zhao, J., Guan, K., Duan, K., 2005. The method for extracting oil & gas from oil shale by convection heating (*CN patent CN1676870A)*. China Nat. Intellect. Proper. Administr.
Zhao, J., Yang, D., Kang, Z., Feng, Z., 2012. A micro-CT study of changes in the internal structure of Daqing and Yan'an oil shales at high temperatures. Oil Shale 29 (4), 357.
Zhao, L.M., Liang, J., Qian, L.X., 2013. Model test study of underground co-gasification of coal and oil shale. Appl. Mech. Mater. 295, 3129–3136.
Zhao, Y., Feng, Z., Feng, Z., Yang, D., Liang, W., 2015a. THM (Thermo-hydro-mechanical) coupled mathematical model of fractured media and numerical simulation of a 3D enhanced geothermal system at 573 K and buried depth 6000–7000 M. Energy 82, 193–205. https://doi.org/10.1016/j.energy.2015.01.030.
Zhao, Y., Yang, D., Liu, Z., Feng, Z., Liang, W., 2015b. Problems of evolving porous media and dissolved glauberite micro-scopic analysis by micro-computed tomography: evolving porous media (1). Transport Porous Media 107 (2), 365–385. https://doi.org/10.1007/s11242-014-0443-z.
Zhao, Y., Feng, Z., Lv, Z., Zhao, D., Liang, W., 2016. Percolation laws of a fractal fracture-pore double medium. Fractals 24 (4), 1650053.
Zhao, H., Xiong, Y., Zhen, H., Liu, C., Li, X., 2022. Experimental investigation on the fracture propagation of three-stage acid fracturing of tight sandstone gas reservoir. J. Petrol. Sci. Eng. 211, 110143.
Zheng, D., Li, S., Ma, G., Wang, H., 2012. Autoclave pyrolysis experiments of Chinese Liushuhe oil shale to simulate in-situ underground thermal conversion. Oil Shale 29 (2), 103.
Zheng, H., Shi, W., Ding, D., Zhang, C., 2017. Numerical simulation of *in situ* combustion of oil shale. Geofluids 2017 (1), 3028974. https://doi.org/10.1155/2017/3028974.
Zhu, J., Yi, L., Yang, Z., Duan, M., 2021. Three-dimensional numerical simulation on the thermal response of oil shale subjected to microwave heating. Chem. Eng. J. 407, 127197. https://doi.org/10.1016/j.cej.2020.127197.
Zich, D., Zacher, T., Darmo, J., Szöcs, V., Lorenc, D., Janek, M., 2013. Far-infrared investigation of kaolinite and halloysite intercalates using terahertz time-domain spectroscopy. Vib. Spectrosc. 69, 1–7. https://doi.org/10.1016/j.vibspec.2013.09.003.