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MASTER'S THESIS

DEVELOPMENT OF INJECTION WELLS SELECTING CRITERIA FOR EFFECTIVE IMPACT ON THE PRODUCTIVE FORMATION IN ORDER ENHANCED OIL RECOVERY

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NEFT HASİLATINI ARTIRMAQ ÜÇÜN MƏHSULDAR LAYA TƏSİR ZAMANI VURUCU QUYULARIN SEÇİLMƏSİ MEYARLARININ İŞLƏNMƏSİ

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INTRODUCTION

The relevance of the topic: This area of research has not received sufficient attention previously, even though the solution to such problems is in significant demand for practical application, which makes the solution to the problem a new and important area of research. Developing criteria for selecting injection wells based on the current distribution of reservoir fluids is essential for improving oil recovery, optimizing energy consumption, and ensuring efficient reservoir management.

Fluid injection, a widely used technique, helps maintain reservoir pressure and sustain long-term production. However, improper well selection and uneven fluid distribution can lead to viscous fingering, early watercut, reduced efficiency, and even complete loss of the field. Therefore, optimizing injection well selection processes and effectively managing the flooding process are essential for maximizing reservoir productivity and long-term sustainability.

The purpose and objectives of the research: The main purpose of this study is to develop scientifically based criteria for selecting injection wells aimed at enhancing oil recovery through optimization of fluid injection strategies within productive formations. This study seeks to address existing gaps in well selection methodologies to improve efficiency and sustainability in reservoir management. The main objective of this study is as follows:

Reducing water cut-offs in wells – This is the process of minimizing the amount of water produced with the oil. It involves developing strategies to prevent excessive water production, which can reduce profitability and oil recovery, while ensuring more efficient oil recovery.

Increasing oil production – One of the main objectives of the study is to determine optimal injection strategies that maximize oil production from the reservoir, considering various geological conditions and reservoir properties, to increase oil production.

Considering previously overlooked factors – The research will highlight factors that are crucial for enhancing well productivity but have been previously ignored. The current hydrodynamic state of the productive layer will be considered as the main factor, along with other aspects that are often overlooked in traditional well selection processes.

Considering the movement of the water-oil contact front – The study will consider the dynamics of the water-oil contact (WOC) front, which plays a crucial role in the efficiency of water injection. Proper monitoring and analysis of WOC movement will help prevent early water breakthroughs, ensure uniform oil displacement, and optimize injection well placement for continuous reservoir operation.

To achieve this goal, the following main tasks will be performed within the framework of the study:

Selection of suitable mathematical formulas and functions and their integration with each other - extraction of regularities.

Building a MATLAB program based on selected mathematical formulas and adjusting it with corrections.

Introduction of data obtained from the selected real oil field into the MATLAB model and testing.

Determination of optimal injection strategies for the field to which the model will be applied.

Analysis of the research results and determination of criteria for selecting injection wells

The object and subject of the research: The object of study is productive formation. A formation is a geological structure located deep in the earth that stores natural resources such as minerals, water, gas and oil. It has density and permeability properties under certain pressure and temperature conditions in the layer in which it is located. Productive formations, as the layers where oil and gas deposits are located, are of great economic importance. Timely information about hydrodynamic state of the productive formation, water and gas flow, pressure changes and geological characteristics are one of the main conditions for the effective development of this formation.

The subject of the study will be injection well. Injection wells are structures used to inject water or other fluids into the ground to maintain oil field pressure, increase productivity and ensure better drainage of the formation. When properly selected, injections increase the productivity of the field and allow for long-term production. However, improperly selected wells can lead to early depletion of the field, a sharp decrease in production, and ultimately the field becomes unusable. In this study, new criteria for selecting injection well will be developed and the application of these criteria in real fields will be investigated.

The novelty and practical results of the research: The scientific novelty of this study is that this topic has not been directly studied before, making it a critical research area. Ignoring these factors leads to inefficient oil recovery, premature depletion of the field, and significant economic losses.

In this research, based on the analysis of the results of the proposed calculations, it helps to make the right decisions to increase the efficiency of oil and gas production in the field and its defined zones. The current distribution of fluid movement is assessed in the productive layer, considering the interference between wells, and on this basis, methods of influencing layers and wells and injection wells are determined. The proposed criteria will enhance recovery rates, establish a more comprehensive framework for field management, thereby improving economic profitability.

CHAPTER I: LITERATURE REVIEW

1.1. General knowledge about the research

Injection wells are an important part of the field of Enhanced Oil Recovery (EOR), which plays a crucial role in optimizing oil recovery from reservoirs. Injection wells play an important role in the EOR process, as they increase underground pressure, which allows oil to flow rapidly to the bottom of the well and extract more oil from the reservoirs.

There are some key parameters for the successful operation of injection wells. These include the injection index, technical parameters, well design and equipment used. The operation mode of injection wells and the methods used are based on the geological characteristics of the reservoir and technological requirements.

In this section, basic information on the applications of injection wells, the equipment used, design and selection criteria are presented. Proper selection and application of wells play a key role in the successful implementation of EOR methods.

1.1.1. Enhanced oil recovery (EOR)

What are resources?

Resources are defined as the amounts of petroleum that naturally occur in the crust of the Earth, both discovered and undiscovered, including amounts already been produced. These resources can be categorized according to their technical and commercial recovery. Resources are classified into several categories:

- Total Petroleum Initially-in-Place (PIIP) - This includes all amounts of oil estimated to exist in naturally occurring accumulations (discovered and undiscovered) prior to production. PIIP is further subdivided into the subsequent categories:

  Discovered PIIP is the amount of hydrocarbons estimated to be contained in known accumulations before production.

  Undiscovered PIIP is the amount of hydrocarbons estimated to be present in undiscovered accumulations.

- Recoverable Resources - These are the amounts of hydrocarbons expected to be recovered from a given accumulation through the application of development projects.

What are reserves?

Reserves are those quantities of petroleum that are anticipated to be commercially recoverable from the given data forward. Reserves must be discovered, commercially recoverable. Reserves are classified into three main categories based on their certainty and project maturity:

- Proved Reserves (1P) - Proved Reserves are those quantities of Petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from known reservoirs and under defined technical and commercial conditions. If probabilistic methods are used, there should be at least a 90% probability that the quantities recovered will equal or exceed the estimate.
- Probable Reserves (2P) - Probable reserves are those extra reserves that have a lower chance of recovering than proven reserves but a higher chance than possible reserves. When probabilistic techniques are applied in this situation, there should be a minimum of 50% chance that the actual amounts recovered will match or surpass the estimate of Proved plus Probable Reserves (2P).
- Possible Reserves (3P) - Possible Reserves are those additional Reserves that suggest they are less likely to be recoverable than Probable Reserves. The total quantities recovered have a low probability to exceed the sum of Proved plus Probable plus Possible (3P) Reserves. This estimate is the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate *(Society of Petroleum Engineers [SPE], 2018).*

Any technique applied after a secondary recovery is a tertiary recovery. Examples of these are hydraulic fracturing, horizontal and multilateral wells, infill drilling, well stimulation, and optimizing the production or injection rates of individual wells *(Lake, Johns, Rossen, & Pope, 2014)*.

Enhanced oil recovery (EOR) methods are crucial for extracting additional oil from reservoirs after primary and secondary recovery stages. EOR methods aim to recover the remaining original oil in place (OOIP). The rate of replacement of the produced reserves by new discoveries has been declining steadily in the last decades, so the increasing oil recovery from the aging resources is a major concern for the oil companies and authorities. There are more than 20 EOR methods, in general all of them can be classified into five main groups *(Alagoz, 2024)*.

1. Gas methods – Injection of hydrocarbon or nonhydrocarbon components into oil reservoirs is gas EOR or gas flooding method. Gases are injected and may include mixtures of hydrocarbons from methane to propane, and nonhydrocarbon components such as carbon dioxide (CO_2), nitrogen (N_2), and even hydrogen sulfide (H_2S) or other exotic gases such as SO_2. The main goal of gas flooding is to ensure that as much of the injected gas as possible comes into contact with the formation and, once in contact, to extract most of the oil. Injection gases are intended to be miscible with previously trapped oil by capillary forces to mixes with the injected gas. The oil components are subsequently driven to production well by the injected gas or hydrocarbon phase. Any volume of injected gas should ideally displace an equivalent volume of reservoir hydrocarbon fluid, resulting in piston-like miscible flow. There are technical and economic screening processes while conducting gas EOR such as identifying potential injection fluids and analogue fields, ranking potential candidate reservoirs for gas flooding and making some initial economic calculations and production rate estimates. A good screening process will consider several key technical factors:
    - Average reservoir pressure and temperature.
    - Reservoir permeability and ability to inject and produce fluids at economic rates.
    - Available miscible gas source and cost.
    - Oil viscosity and minimum pressure for miscibility.
    - Residual oil saturation to waterflooding.
    - Reservoir heterogeneity and geometry; gravity effects and vertical permeability *(Sheng, 2013)*.
2. Waterflooding methods - Water flooding is the process of water being injected into the formation to maintain pressure and displace oil. In water flooding, water is injected into one or more injection wells, and oil is extracted from surrounding production wells as appropriate *(Lake, 2014)*.
3. Thermal methods - Thermal methods supply heat to the reservoir and vaporize some of the oil. The major mechanisms include a large reduction in viscosity, and hence mobility ratio. Other mechanisms, such as rock and fluid expansion, compaction, steam distillation and vis breaking

may also be present. Thermal methods have been highly successful in Canada, USA, Venezuela, Indonesia and other countries *(OJHA, 2023)*.

The most significant displacement mechanism used in thermal method of EOR is the reduction of crude viscosity as temperature rises. The crude kinematic viscosity decreases sharply with increasing temperature. Therefore, thermal methods are not profitable for these hydrocarbons, especially since water flooding would be a more attractive alternative. Despite the viscosity reduction is considerable for heavy HCs, it is not enough to make them flow economically. Therefore, there are practical limits on both viscosity extremes. All thermal recovery processes move or transport energy (usually heat, hot steam) into or through a reservoir to recover HCs. The basic heat-transfer mechanisms are:

- Steam Soak - In a steam soak (also known as cyclic stimulation or huff-n-puff), steam is put into a well, and then the well is started to production after a brief shut-in period. The steam heats up a zone near the well and provides some pressure support for the latest production. The steam is injected from production well itself into subsurface. Thermal gradients can equalize during the shut-in or soak time, but it shouldn't last long enough for the pressure to release. During shut-in, all the injected steam condenses and increase mobility of crudes. After, the well produces a mixture of hot water and HCs. One great advantage of a steam soak is that all the wells can be produced nearly all the time, the injection and soak periods usually being short.
- In-Situ Combustion - The process injects some form of oxidant (air or pure oxygen) into the formation. The mixture then spontaneously ignites (or ignition is induced), and the subsequent injection propagates a fire or burn zone through the reservoir. The fire zone is only a meter or so wide, but it creates very high temperatures. Connate water and some of the crudes are vaporized at these temperatures. Steam zone front is formed by the vaporized connate which operates very much like a steam drive. Light components that form a miscible displacement make up most of the vaporized oil. In addition, an in-situ carbon dioxide (CO_2) flood may be created by the reaction products of high-temperature combustion. One term for in-situ combustion processes is high pressure air injection (HPAI).
- Steam-Assisted Gravity Drainage (SAGD) - SAGD uses horizontal rather wells and these horizontal wells are in injector/producer pairs that are closely spaced. Closely spaced injectors and producers would be unsuccessful because such close well spacing

would result in early breakthrough and extensive bypassing of oil. However, buoyancy is the main recovery mechanism of SAGD, rather than viscous driving forces.

- Steamdrive - A steamdrive uses at least two sets of wells, one of them is for steam injection and the other for HCs production. A steamdrive usually results in higher recoveries than a steam soak thermal method because it penetrates more deeply into the reservoir. Also, the distances between the wells should not be close *(Lake, Johns, Rossen, & Pope, 2014).*

4. Physical and Chemical EOR- Depending on the temperature, pressure, and chemical composition of the injected fluid, physical and mechanical property changes may occur in the reservoir, such as hydraulic fracturing or, conversely, fracture closure and clogging. Water soluble polymers and/or surfactants are added to water that is injected into the subsurface. Polymer-loaded water has a high viscosity and can push more oil out of the pores in the oil-bearing formation. Surfactants reduce the surface tension of the oil, improving its ability to be displaced by water *(James J. 2011).*

   The chemical flooding EOR can be categorized into two 2 main groups:

   - Polymer flooding - A water-soluble polymer is dissolved in water to reduce its mobility as injected water passes through a porous material. This process is known as polymer flooding. As a result, the viscosity of the water increases, allowing for easier movement of the HCs. This leads to a decrease in the permeability of the water phase compared to injection of water without polymer. This reduction of the mobility ratio increases the efficiency of the waterflood.
   - Surfactant flooding. Surfactants are injected into the reservoir to reduce IFT and mobilize oil. Surfactants are surface-active agents that lower the surface tensions between two immiscible phases, such as oil and water. İt is crucial in terms of reducing interfacial tension (IFT). Surfactants are crucial because they reduce interfacial tension (IFT), which helps to mobilize oil trapped in reservoir rock pores. Surfactants can either be injected directly into the reservoir or used in combination with other substances such as polymers. Surfactants are classified into four main types based on their charge in aqueous solutions: 1) anionic surfactants 2) ationic surfactants 3) nonionic surfactants 4) amphoteric surfactants.

Lowering the capillary forces by injecting surfactant, making it easier to displace the trapped oil within reservoir *(Lake, Johns, Rossen, & Pope, 2014)*.

5. Hydrodynamic EOR - It is an increase in oil recovery by adjusting liquid flow in wells. Close to the well in the well, the closing of the well in the well, the injection rate in any well, etc. Hydrodynamic methods of increasing oil production are divided into:
   - Use of integrated technologies.
   - Obstacle floods in gas and oil fields.
   - Non-stationary floods.
   - Production of raw materials using the forced removal of liquid *(Al-Obaidi, 2021)*.

1.1.2. Injection wells

An injection well is a specialized well designed to inject gas, liquid, air, or heat carriers into a productive reservoir to maintain reservoir pressure and enhance oil recovery. The primary function of such wells is to replace reservoir fluids. Studies on injection wells have demonstrated their significant role in the oil extraction industry.

Injection wells for oil production are designed to inject water or gas into gas caps, meaning outer boundary areas of oil deposits, using pressure maintenance methods and across the entire reservoir, a preferred method in secondary oil recovery techniques. Injection wells are mainly used in oil field development and, to a lesser extent, in oil and gas-condensate fields *(Billiter & Dandona, 1999)*.

1.1.3. Advantages of using injection well

Research on injection wells has shown several advantages over other types of wells:

- Maintaining the required reservoir pressure.
- Controlling and regulating the extraction rate of hydrocarbons.
- Injecting working agents into oil reservoirs, which helps enhance oil displacement efficiency and supports in-reservoir combustion processes.

The design of an injection well depends on its purpose, operational tasks, predicted depth, and other technical parameters.

1.1.4. Technical parameters and operation of injection wells

Oil must be evenly displaced by water across the entire injection-to-production well front. To achieve this, the total injection volume, number of injection wells, pressure, and injectivity of each well are calculated. During field development planning, a well placement scheme is designed based on daily production rates and reservoir characteristics. For area-wide waterflooding, a 4 to 7-point pattern of injection wells is typically used to ensure optimal reservoir pressure maintenance. However, in practice, it is often not possible to use this scheme in old fields. The interference of old wells with new injection wells, the limitations of inefficient well placement, and the difficulty of establishing such patterns in offshore conditions make it impossible. To find the best strategy, it is important to know the well water-oil flow rates, well trajectories, well placement, and, above all, the hydrodynamic situation in the formation. Choosing the most optimal and cost-effective method requires an analysis of the hydrodynamic situation in the formation.

Injection wells are designed to replace reservoir fluids with special gases or liquids. Besides water injections, other methods include steam injections and solvent injections to enhance oil recovery.

Other Key Characteristics of Injection Wells:

- Productivity coefficient – Measures the efficiency of fluid injection.
- Energy consumption – Determines the power required for injection operations.
- Specific energy consumption – Energy required to compress 1 cubic meter of water to1 MPa.
- Average well lifespan – The expected operational duration of the well.
- Pump efficiency – The effectiveness of the pumping system.
- Well construction cost – The total expense of drilling and completing the well.
- Wellbore radius – The effective radius of the well for fluid movement.
- Skin factor – The degree of clogging in the reservoir around the wellbore. It refers to blockages or permeability reduction around the wellbore due to particle deposition, chemical reactions, or fluid interactions, affecting injectivity and requiring stimulation for restoration. The skin factor is a value used to measure the effect of skin. The deviation from Darcy's law caused by the effect of skin in the wellbore can be analytically modeled using this numerical value. It is a dimensionless parameter, and a negative value indicates an

improvement in the productivity of the well, while a positive value indicates a decrease. It also serves as a method to determine the flow efficiency of the well. Skin can mainly be caused by formation damage, poor well completions, and well deviations. Skin factor is one of the main problems in oil production because it causes additional pressure loss around the wellbore. Thus, there is a decrease in the flow of oil from the reservoir to the surface facilities. *(Raji et al., 2020)*

- Reagent viscosity – The thickness and flow properties of the injected fluids.

1.1.5. Injectivity index

The injectivity index is the key technical parameter for injection wells. Equipment performance and technical condition monitoring are carried out using methods such as acoustic logging, thermometry, and flow metering.

When working with the presented type of wells, it is necessary to consider such a technical parameter as the injectivity of the injection well. Injectivity defines the well's ability to receive injected fluid and is determined by:

- Drawdown pressure - The difference between the reservoir pressure and the flowing wellbore pressure, which drives fluids from the reservoir into the wellbore *(Larsen, 1984),*
- Reservoir permeability- Affects fluid movement through the formation.
- Thickness - Determines the overall storage and flow capacity.
- Efficiency of reservoir exposure - The quality level of the reservoir exposure process during field development. It refers to the effectiveness of drilling and completion in ensuring optimal connectivity between the wellbore and the oil reservoir for efficient production.

The injectivity index is calculated as the ratio of the injected fluid volume to the drawdown pressure at the moment of injection. The consumption rate of the injected agent is measured at the surface. In some cases, a well can function as both a production and injection well at different reservoir levels, with the zones being isolated by packers. The key performance metric of an injection well is its injectivity index *(Yudin, Eltaher, AlYaseen, Al-Jalal, & Faisal, 2024).*

1.1.6. Injection well applications

Injection wells are widely used in oil and gas extraction for (a) reservoir pressure maintenance and production regulation, (b) improved oil displacement through water, gas, or chemical injections. These injected agents help displace oil toward production wells, reducing the load on pump equipment and increasing oil production rates. There is significant usage of injection wells on (c) underground gas storage processes.

1.1.7. Equipment used in injection wells

The equipment used in injection wells is classified based on technological function. The first one is wellhead equipment. This includes both surface and subsurface components. The second one is injection equipment. It covers water intake, treatment, pumping stations, and pipelines.

Equipment in injection wells falls into two main categories based on where it used to:

1) Subsurface equipment (installed inside the well)

   Packers – Provide zonal isolation within the wellbore, tubing, casing, or annulus *(Antonio, Barrios, & Martinez, 2007).*

   Filters – Ensure long-term fluid injection into the reservoir. Prevent clogging during fluid injection.

   Tubing columns – Serve as the main conduit for injected fluids.

   Anchor – Relieves stress on the tubing string and prevents lateral packer displacement.

2) Surface Wellhead Equipment

   Casing head – Secures all casing strings to the surface.

   Piping assembly – Holds the tubing string and seals the annular space.

   Injection manifold – Seals the wellhead, controls injection modes for gases/fluids, and facilitates well flushing and bottom-hole testing.

1.1.8. Injection well design

Injection wells have both standard and unique design features. The essential design points are wellbore bottom, wellhead and casing string. Wellbore bottom (pay zone level) is equipped with filtration devices to regulate fluid flow. Wellhead (surface level) is sealed with tight fittings and specialized injection equipment. The wellbore consists of casing columns with internal tubing columns.

Distinctive features of injection wells

- Flow direction: From top to bottom, moving from the wellhead to the bottom.
- Operating pressure: 14 – 35 MPa.
- Nominal diameter: 50 – 80 mm for both the main wellbore and side branches.
- Presence of check valves to control fluid movement.
- Full-length cementing of the casing column from the wellhead to the bottom for well integrity *(Gumarov et al., 2014).*

The structure of injection wells depends on operational tasks and reservoir characteristics. It depends on the rock properties. If the rocks are stable, the well bottom remains uncased. If the rocks are unstable, the casing is lowered into the bottomhole area. In this case, it is necessary to perforate the bottomhole area.

Main design features include:

- Wellhead equipment fitted with pressure gauges and valves.
- Pump-compressor pipes (tubing) placed down to the top of the absorbing reservoir.
- Cementing the space behind the casing to ensure well integrity.
- Packers are used in unstable formations for additional sealing *(Plessing & Macdonald Arnskov, 2011).*

Injection wells are classified based on the complexity of their development, which is divided into three categories *(Li et al., 2024):*

1. Wells in sandy formations – High permeability, easier to inject fluids.
2. Wells in clay-rich formations *(Bhatnagar, Anantharamu, & Bianco, 2024)* – Low fluid absorption capacity, making injection more difficult.

3. Wells in mixed formations – A combination of sand and clay, with approximately equal proportions.

1.1.9. Methods of well flow stimulation

There are several ways to stimulate the flowing process of fluids which flows from reservoir to wellbore such as methods:

- Hydraulic fracturing: High-pressure pumps (100 MPa, 40 L/s flow rate) are used to enhance rock injectivity.
- Acid treatment: 8–20% acid solution with 40% formalin is injected to dissolve carbonate formations while preventing corrosion in steel pipes *(Jeppsson & Anehus, 1995).*
- Steam injection: Tubing strings are equipped with thermal expansion compensators to handle high temperatures.

1.1.10. Injection Well Operating Modes

By default, an injection well can be placed inside or outside the oil-bearing contour:

- Peripheral (extra-contour) flooding – Wells are located 400–800 meters outside the reservoir; used for small fields with high reservoir quality.

- Edge (near-contour) flooding – Wells are placed within the water-bearing zone of the reservoir; used when hydrodynamic connectivity between the outer area and the reservoir is low, typically for small oil deposits.

- Intra-contour flooding – Wells are drilled inside the oil-bearing area; applied in large reservoirs to improve displacement efficiency *(Malozyomov et al., 2023).*

So, an injection well is used for injecting water, gas, heat carriers, and air mixtures into the productive reservoir to maintain reservoir pressure and achieving uniform displacement of oil from the layers. Unlike production wells, which extract reservoir fluids, injection wells inject liquid (water), thus replacing the reservoir fluid in the reservoir. At most fields, reservoir pressure is maintained by injecting water into wells located either outside or within the reservoir's contour. If the water injection well is outside the oil-bearing contour, the rock is 100% saturated with water, making well development easier *(Feng et al., 2017).*

If the well is within the oil-bearing contour, the oil saturation coefficient of the rock is significantly higher than the water saturation coefficient, complicating the well development due to the need for work to reduce the oil saturation of the near-wellbore zone of the reservoir.

1.1.11. General Injection Well Selection Criteria

Selecting an injection well for enhanced oil recovery is an important step in implementing enhanced oil recovery methods. Here are some key aspects to consider:

1. **Geological Conditions** – A detailed geological study is required to understand the characteristics of the reservoir, including porosity, permeability, pressure, temperature, and fluid composition.
2. **Production Rate and Reservoir Condition** – Analyze existing well production data in the region. Identify the most promising areas for injection. If the reservoir is already water-cut or has high oil viscosity, a special stimulation strategy may be required.
3. **Choice of Injection Technology** – Depending on the reservoir conditions, select the appropriate technology, such as water injection, gas injection, or chemical flooding. Each method has its advantages and disadvantages.
4. **Well Location** – Design the placement of the injection well to ensure the best impact on the target reservoir. Consider factors such as the distance to production wells, spacing between injection and production wells, and possible influence zones.
5. **Economic Calculations** – Conduct an economic feasibility analysis of the selected strategy. This includes evaluating drilling and equipment costs, operational expenses, and the expected incremental oil recovery.
6. **Modeling** – Use hydrodynamic modeling to predict the efficiency of various injection scenarios. This helps optimize injection parameters and understand the interaction between injected fluids and the reservoir.
7. **Monitoring and Adjustments** – After the injection well is put into operation, continuous monitoring of its performance and reservoir conditions is necessary. This allows for strategic adjustments based on observed results.

1.1.12. Platforms for digitizing calculations

Digitalization of calculations plays an important role in modern engineering fields *(Atajonova, 2025)*. Traditional methods are increasingly replaced by more flexible, accurate and functional digital platforms. Such platforms allow modeling, simulation and analysis of various systems, which leads to a reduction in both time loss and real testing costs.

Within this work, there are several important simulation and modeling platforms that have a wide range of applications. Examples of them are the following:

- Eclipse (Schlumberger) - One of the most popular reservoir simulation tools available is ECLIPSE. It enables the modelling of thermal, gas, water, and black oil flow processes. ECLIPSE is commonly used to evaluate production scenarios and match historical data under realistic geological and technological situations *(Schlumberger, n.d.-a),*
- Petrel (Schlumberger) - Petrel software allows to create reservoir models from the geological structure to the simulation stage. Petrel enables you to generate both dynamic and static models.it is integrated with ECLIPSE *(Schlumberger, n.d.-b).*
- CMG – IMEX / GEM / STARS (Computer Modelling Group) - The CMG software package offers modeling capabilities for various flow regimes and phases: 1) IMEX - black oil model for water and oil systems. 2) GEM - composition-based simulation (gas injection, etc.). 3) STARS - for thermal and chemical EOR processes *(Computer Modelling Group, n.d.).*
- tNavigator (Rock Flow Dynamics) - tNavigator is a modern and high-performance dynamic reservoir simulation platform. It is intended to do uncertainty analysis, production optimization, history matching, and the creation of static models *(Rock Flow Dynamics, n.d.).*
- REVEAL (Emerson / Roxar) – REVEAL is a software program designed for chemical, thermal, and composition-based models. It is particularly useful for simulating high temperatures and unusual flow regimes (Emerson, n.d.).
- The Nexus platform is distinguished by its parallel simulation capabilities and is suitable for dynamic simulation of large-scale areas (Halliburton, n.d.).
- MATLAB – It is a high-level programming environment. It is an excellent platform for mathematical calculations, data visualization, algorithm development, and simulation. There are several uses for MATLAB in physics, engineering, and other scientific fields *(MathWorks, n.d.).*

The above programs are good tools for reservoir modeling, but their simulation or modeling processes are based on existing mathematical formulas and laws. The formulas here are all theoretical and stable. However, since the formulas and calculations we will use cannot be performed with any of the programs mentioned, we will build our own program in the MATLAB program interface.

1.1.13. Tracer indicator

Tracer indicators are effective surveillance tools with many useful applications. applications of tracer are enhancement in residual oil saturation (Sor), waterflood optimization, and connectivity between wells. Tracers can be categorized in a few ways:

- In accordance with their functions: passive tracers and partitioning. Compared to passive tracers, partitioning tracers spread more slowly because of their interactions with the reservoir. To evaluate and optimize EOR operations, Sor can be estimated using the time lag between the two types.
- Based on their carrying fluid, can be water or gas tracer. This feature is an advantage in EOR processes. All gas tracers are partitioning tracers and they are environmentally friendly, thermally stable, and highly detectable. Water tracers are passive tracers.
- Based on radioactivity, for example there are radioactive and non-radioactive tracers. The selection of the most suitable tracer to use in the fields depends on detectability, cost, solubility, compatibility and environmental impact *(Tayyib, Al-Qasim, Kokal, & Huseby, 2019)*.

Tracer technology has many positive aspects, but there are also some negative aspects. For example, this technology requires high costs, because the operations carried out for about 3 wells cost about 200 thousand manats. Also, the observation process can last a long time, for months, and this also requires additional time. The application of tracer technology also requires additional work, such as constant observation and taking tests and analysis. Finally, tracers cannot be reused after being used once, because they are unique for each well *(Ibragimov, Huseinova, & Gadzhiev, 2021)*.

1.2.1. Well screening criteria for WSO

There is almost no work done in this area, but there are several similar works that use injection well selection criteria. For example, *Serhat Canbolat and Mahmut Parlaktuna (2012)* conducted a study on well selection criteria for water shut off (WSO) polymer gel injection in carbonate reservoirs. Their research focused on developing a systematic approach to identifying suitable wells for polymer gel treatment, aiming to mitigate excessive water production in naturally fractured reservoirs. They analyzed reservoir rock and fluid properties, production history, and well characteristics to determine the best candidates for polymer gel injection. Key selection criteria included fracture density, water cut levels, remaining recoverable oil, productivity index (PI), well completion type, and salinity trends. By integrating these factors, they built a reservoir simulation model to evaluate the effectiveness of WSO treatment on oil recovery and economic feasibility.

Their findings demonstrated that wells with high fracture density, high PI values, and high-water cuts were the most suitable candidates. So, they built these selection criteria for well selection:

1. Permeability / fracture distribution: In carbonate reservoirs secondary porosity is one of the key characteristic features. Carbonates may develop a variety of secondary porosity forms, including fractures, vuggy, channels, and moulds because of variations in the diagenetic processes and depositional environment. When secondary porosity reaches a certain value, it may enhance permeability and subsequently increasing production. Fracture identification logs indicate numerous fractures that increase permeability (Ghafoori et.al, 2008). The first criterion for higher water-cut is higher fracture density and/or higher permeability (Demir et al., 2009), (Larson et al., 1999), (Perez et al., 2001). In his study, the formation micro scanner (FMS) images were used to analyze natural fractures on six wells of the field. According to the investigation, some of the natural fractures in each well were classified as cemented or sealed fractures, while the remaining fractures were either totally or partially open. Using gridding techniques, a field fracture distribution map (Figure 1.2.1) is created over the field using the natural fracture values found in the interpretation research. According to the fracture distribution map, the field's east and center (apex) have more fractures than the rest of the field (GeoQuest, 1998).
2. Water cut value of the well: Water cut value of the well: Higher water-cuts producing or abandoned wells, at or near at their economic limit are good candidates for WSO application. Wells that reached the high-water cuts values in their early production life and continuing to produce with high water cuts are also appraised to be ideal candidates.
3. Remaining recoverable oil-in-place: After the water shuts off polymer gel injection operations, the wells should be examined to see if there is enough recoverable oil left for production. The calculation of the Remaining Recoverable Oil (RRO) for each well is considered for the selection criteria (Burrafato et al. 1999). When an aquifer is inked with the water phase of a

carbonate reservoir, pressure can be generated to push oil from the reservoir to the well head. Typical OOIP oil recovery efficiencies are 35 to 75%. Common types of aquifers: bottom and edge. Depending on aquifer strength, reservoir pressure remains the same. Producing GOR is unchanged until reservoir pressure declines below bubble point (Dake, 1978). The main uncertainty in volumetric reserves calculations for different reservoir types at different stages of development and depletion might be recovery factor, fluid saturation, rock volume, or effective porosity. Significant considerations influencing a volumetric reserves estimate are listed below: Rock volume may simply be determined as the wellbore net pay and product of a single well drainage area. Recovery factor is determined by engineering analysis, analysis of production behavior from the subject reservoir and/or by analogy with other producing reservoirs. The evaluator must consider factors that affect recoveries, such as fluid and rock properties while evaluating recovery factors. To calculate remaining oil in each well, porosity, Sw, formation volume factor, average pay zone thickness, area OOIP values calculated for each well. Using the below equation for recovery efficiency from Guthrie and Greenberger (Arps, 1956):

$$E_R \equiv 0.2719\, log\, k - 0.255569 S_w - 0.1355\, log\, \mu_0 - 1.53\phi - 0.0003488h + 0.11403 \quad (1)$$

values determined for each zone in the reservoir. RRO can be computed for each well subtracting the oil recovery numbers as of June 2011 from the recoverable oil in place. Regarding the calculations, the summary of RRO in place with Total Recovery Fraction (TRF) of the wells in field organized and allocated to the selected wells listed in Table 1.2.1. for screening criteria for well selection *(Canbolat & Parlaktuna, 2012).*

4. The wells with High PI values are ideal candidates for injecting polymer gel to reduce high water cuts. The fracture distribution map in Figure 1.2.1. and the calculated PI values of the candidate field wells are close, as seen in Figure 1.2.2. This confirms that in reservoirs with naturally fractured, the fracture density controls the fracture permeability and thus dictates the production performance of reservoir and PI values. Table 1.2.2. presents the analysis of the well's production data, fluid levels, and PI values for the candidate field *(Canbolat & Parlaktuna, 2012).*

5. Well Completion: Good cement bond behind the casing string or short open hole lengths are plus for the selection criteria situation (Der Sarkissian, 2005). That's why wells completed as cased hole or having short pay zone under the casing (open hole) are the selected candidates.
6. This is another criterion for the selection criteria of the candidate wells, whether the produced water is from the reservoir or aquifer. The most common reason for high water production is the presence of fractures in the reservoir, which cause water to flow in different directions (Willhite and Pancake, 2004). The measured water salinity values of candidate wells with a decreasing trend with time is shown Table 1.2.3. This is an indication that aquifer water is flowing through the fractures into the wellbore, bypassing the remaining oil *(Canbolat & Parlaktuna, 2012).*

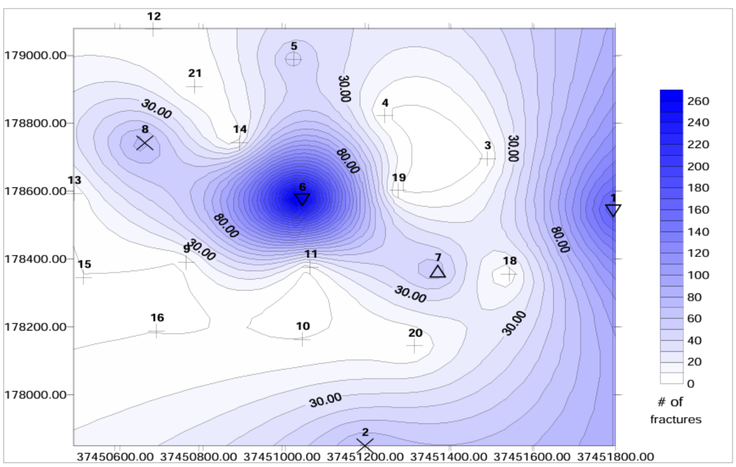

Figure 1.2.1. Field fracture density distribution map.

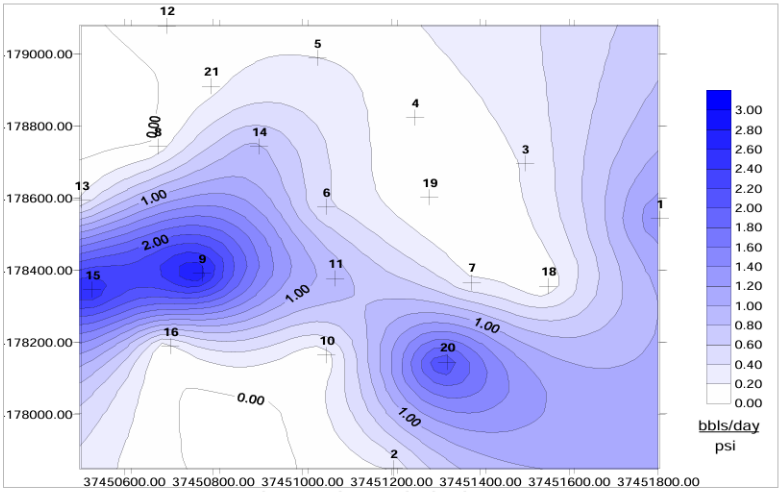

Figure 1.2.2. Field PI distribution map.

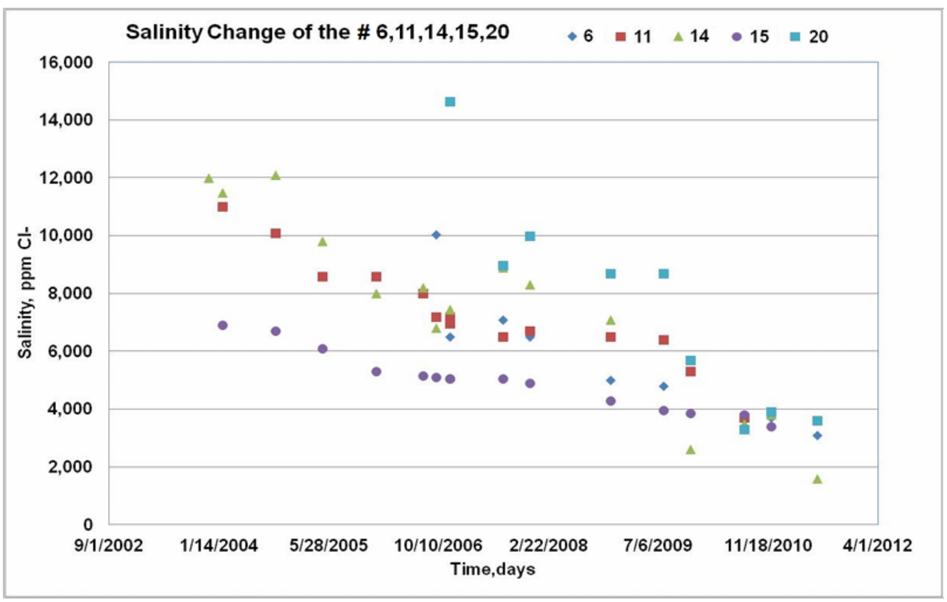

Figure 1.2.3. Candidate wells salinity change.

Table 1.2.1. Summary of RRO and TRF of selected field wells as of june 2011.

Well #	Total ROIP bbls	Production bbls	Remaining Oil bbls	Total Recovery fraction
4	308,619	121,542	187,077	0.39
6	**231,314**	**77,100**	**154,214**	**0.33**
7	440,558	293,169	147,389	0.67
9	455,572	342,865	112,707	0.75
11	**175,299**	**73,556**	**101,743**	**0.42**
12	191,512	70,076	121,436	0.37
14	**284,998**	**99,415**	**185,583**	**0.35**
15	**364,936**	**167,890**	**197,046**	**0.46**
16	173,779	44,479	129,300	0.26
20	**133,826**	**21,881**	**111,945**	**0.16**

Table 1.2.2. Productivity index (PI) for the wells in june 2011.

Well #	Fluid Level ft	BHP psi	Prod. Rate bbls/day	PI bbls/day/psi
9	**750**	**1753**	**564**	***2.87***
15	**749**	**1726**	**600**	***2.68***
20	**885**	**1628**	**720**	***2.24***
11*	**1488**	**1430**	**492**	***0.95***
14	**1651**	**1217**	**640**	***0.87***
6*	**712**	**1707**	**110**	***0.45***
7	2027	1093	216	0.25
13	2708	836	175	0.16
4	2691	875	115	0.11
12	4510	103	176	0.10

*Abandoned wells. **Shut in Wells

Table 1.2.3. Summary of field wells production ınformation for candidate selection as of june 2011.

Well #	Number of Fractures	PI bbls/day/psi	Cumulative Production, bbls	Water cut, %	Penetration, ft	Producing, zone	Remaining Recoverable Oil, bbls	Completion Type	Salinity ppm Cl-
6	291	0.45	77,100	99	58	A,B	154,214	Cased	2300
11	60	0.95	73,556	99	101	A,B,C	101,743	Open	3100
14	50	0.87	99,415	98	327	A	185,583	Open	2200
15	50	2.68	167,890	98	54	A	197,046	Open	2800
20	50	2.24	21,881	99	253	A	111,945	Open	2800

The simulation results showed a significant reduction in water cut from 95–99% to 61–67% and an incremental oil recovery of 15,763 barrels over ten months.

Despite these promising results, some gaps remain. The study primarily focused on short-term performance and specific well conditions, leaving uncertainties regarding the long-term stability of the polymer, potential formation damage, and the effects of different geological conditions. Furthermore, alternative WSO methods and their comparative effectiveness have not been comprehensively investigated. To enhance well selection models and increase the sustainability of WSO treatments in fractured carbonate reservoirs, future research could focus on these areas *(Canbolat & Parlaktuna, 2012)*.

1.2.2. Well selection methods for high-pressure water injection in fractured-vuggy carbonate reservoirs

Another study conducted by Xin Ma, HaiTao Li, HongWen Luo on well selection methods for high-pressure water injection in fractured-vuggy carbonate reservoirs, focusing on Tahe Oilfield in China. Their research also aimed to address the challenges associated with excessive water production and declining reservoir energy in these complex geological formations. The study developed by analyzing karst characteristics, reservoir structure, and reservoir parameters. The researchers establish screening criteria for choosing appropriate wells, such as the existence of multiple karst caves, fractures with high permeability, and low formation energy. The Tahe oilfield's carbonate fractured vuggy reservoir is kind of reservoir with strong heterogeneity. The analysis findings of several factors impacting high-pressure water injection's efficacy were considered. Engineering methods, geology, and reservoir analysis were all combined in an integrated research approach. Methodical approach to well selection for high-pressure water injection will be developed. The approach will consider the structure of the reservoir, the karst system, and reservoir parameters, particularly for vuggy reservoirs with carbonate fractures.

High-pressure water injection require good geological foundation for high efficiency. Thus, the tensor attribute map and seismic profile analysis of the high-pressure water injection well indicates that the following are the clear features of the oil growth effect: 1) geological data indicates the there are many abnormal formations surrounding the well, with a broad horizontal distribution; 2) the distal fracture cavity body is distributed in the middle and lower part.

Field data and high-pressure water injection wells with various reservoir structures were analyzed, and it was found that the oil increase effect is more significant when the reservoir structure is either double cave or fracture cave. This is since both structures have untapped reservoirs to varying degrees, and the size of their reserves typically aids in the oilfield's economic growth. In addition, these structures have the potential to connect to remote reservoirs. Therefore, high-pressure water injection increases oil production more effectively than others while usage in fractured or double-cave formations.

As a result, the procedure for screening wells for high-pressure water injection in a fractured vuggy carbonate reservoir is as follows:

- Fracture cave type or double cave type reservoir type is preferred. Because under this type, it contains abundant residual oil and is surrounded by two or more undeveloped reservoirs set near the well.
- Fault and paleochannel karst are favorable. This reservoir offers a strong geological basis for improved oil recovery because of its well-developed karst features and the well-connected fractures along the fault direction.
- Under the condition of conventional water injection for oil replacement single wells with weak far well energy (less than 40 MPa) and large fracture start-up pressure difference (greater than 17Mpa) are preferred. The large initial pressure differential makes it difficult to open the distal fracture channel, the spread range is limited, making it hard to supplement energy to far wells. However, the potential of more oil recovery can be achieved by using the high-pressure water injection development method to activate the fracture channel and restore energy to the far wells.

Their findings showed that implementing high-pressure water injection led to an average incremental oil production of 3,211 tons per well. This confirmed the feasibility and economic benefits of their proposed well selection approach.

However, the applicability of this method in different carbonate reservoirs remains uncertain, suggesting the need for further field trials and optimization of well selection criteria *(Ma, Li, Luo, Nie, Gao, Zhang, Yuan, & Ai, 2022).*

1.2.3. Streamline simulation technology and applications

Datta-Gupta et al. (2007) provides a comprehensive framework for modeling and interpreting the distribution of hydrodynamic conditions in the reservoir, using streamline-based approaches to capture flow behavior and pressure distribution with high spatial resolution. Their work begins with derivation of the mathematical foundation of streamline-based modeling, introducing the time-of-flight coordinate transformation that enables the reduction of complex multidimensional flow problems. The focus is on the decoupling of the pressure and saturation equations, allowing one to solve pressure to obtain velocity fields, and then solve the transport equation along streamlines. *Datta-Gupta et al. (2007)* addresses the including of nonlinear flow effects such as relative permeability, gravitational segregation, and viscous crossflow. The authors introduce techniques such as Pollock's method for streamline tracing and discuss issues like streamline crowding and grid refinement. The concept of streamtubes and their volume calculation is introduced, which enables mass conservation and accurate tracking of fluid front propagation. The chapter outlines how Time-of-flight (TOF) maps are generated and used to solve transport equations efficiently. Advanced simulation capabilities, such as the modelling of capillary pressure effects and the integration of compositional and compressible flow behavior, are further explored in their research. The authors also discuss streamline-based diagnostic tools such as flux maps, connectivity maps, and drainage/recharge volumes.

Datta-Gupta et al. (2007), inter-well interference was not considered.

Criterias of injection well selection based on *Datta-Gupta et al. (2007)*:

Geological conditions - The time-of-flight plots show detailed variations from layer to layer but are largely dominated by the vertical injector geometry and good vertical communication within high-permeability regions of the reservoir. In naturally fractured reservoirs, fluids generally exist in two systems viz. the rock matrix, which provides the main bulk of the reservoir volume and storage and the highly permeable rock fractures, which provide the main path for fluid flow.

Injection strategy – 1) The strategy is of the "bang-bang" type, in which each well takes the extreme values in the allowed range, e.g., 0 and 100%. Figure 1.2.4. shows the sequence of flooding stages. 2) The flood should start with the injection as far as possible from the producer, to maximize the oil swept toward the producer. "Distance" is measured in time to breakthrough if only that single injector were flowing. The improvement in sweep efficiency over the optimal steady-state strategy is shown in Figure 1.2.5. (Datta-Gupta et al., 2007).

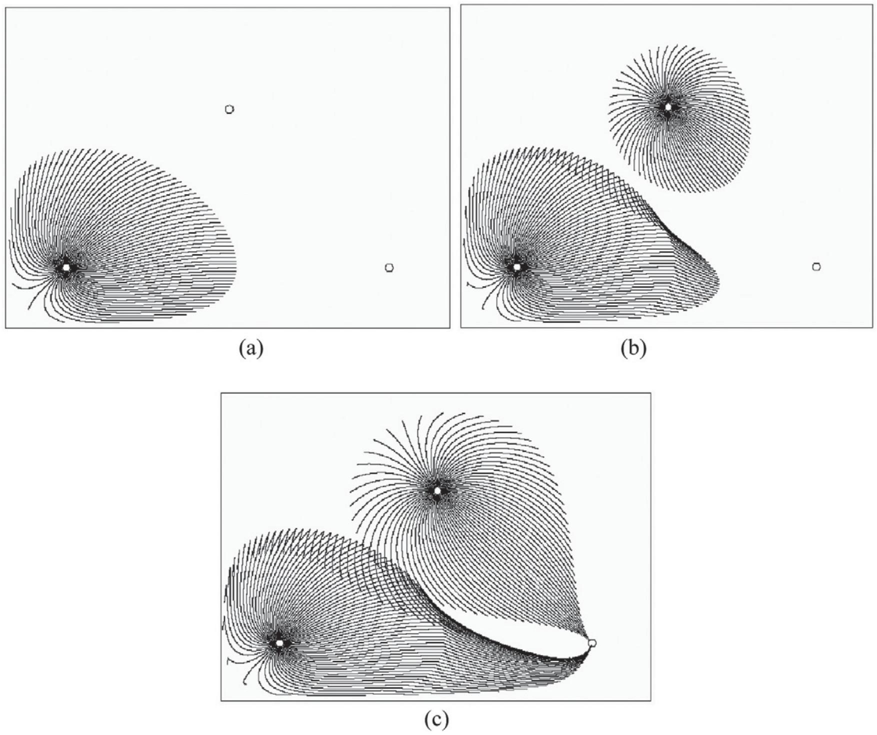

Figure 1.2.4. Optimal bang-bang injection strategy: (a) at well A shut-in, (b) during well B injection, (c) at breakthrough *(from SPE 71509 Sudaryanto and Yortsos, 2001).*

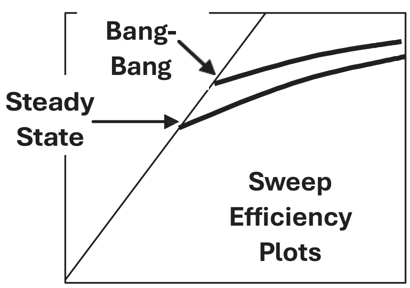

Figure 1.2.5. Schematic of optimal bang-bang and steady-state sweep efficiencies.

The flood fronts at breakthrough are shown for the optimal steady-state and bang-bang injection strategies for a heterogeneous correlated permeability field. On Figure 1.2.6 the flood fronts at the point of breakthrough are illustrated for both the optimal steady-state and bang-bang injection methods within a heterogeneous correlated permeability field. The bang-bang strategy clearly gives a better sweep:

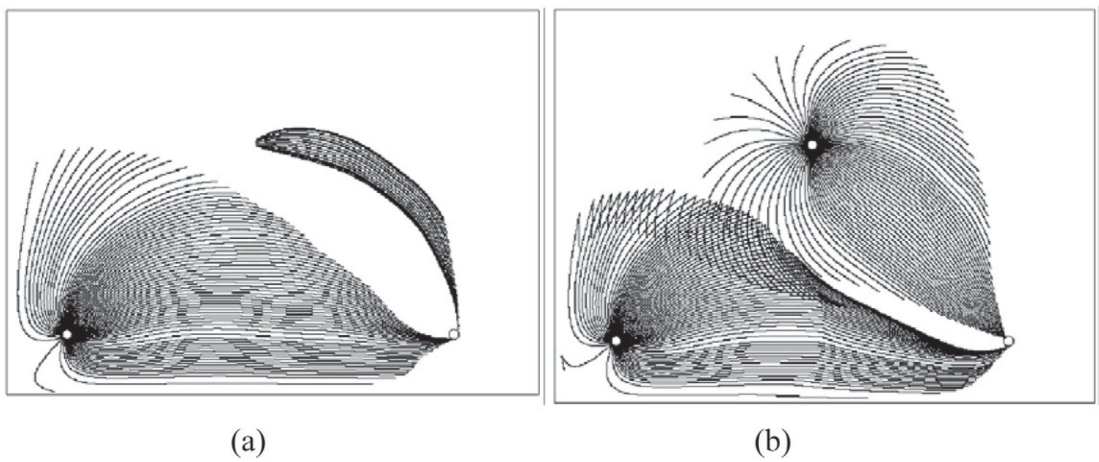

Figure 1.2.6. Optimal bang-bang and steady-state flood patterns in a heterogeneous correlated permeability field: (a) constant rate, (b) bang-bang *(from SPE 71509 Sudaryanto and Yortsos, 2001).*

3) Balancing pattern breakthrough times provides the best sweep, for both the steady-state and the unsteady-state strategies. 4) Multiple simultaneous injections will generate stagnation regions between the injectors, decreasing sweep efficiency. These stagnation regions are hydrodynamic traps that will always form between injectors.

Modelling - The most optimal type of modeling depends on the characteristics of the reservoir, the accuracy of the available data, computational resources, and the purpose of the analysis. Figure 1.2.7 schematically demonstrates the applicability of a streamline vs. finite-difference simulator under various conditions *(Datta-Gupta et al., 2007)*.

The computational advantage of the streamline methods can be attributed to four principal reasons:

1) Streamlines may need to be updated only infrequently.
2) The transport equations along streamlines can often be solved analytically,
3) The 1D numerical solutions along streamlines are not constrained by the underlying geologic grid stability criteria, thus allowing for larger timesteps

4) For displacements dominated by heterogeneity, the CPU time often scales nearly linearly with the number of grid blocks, making it the preferred method for fine-scale geologic simulations.

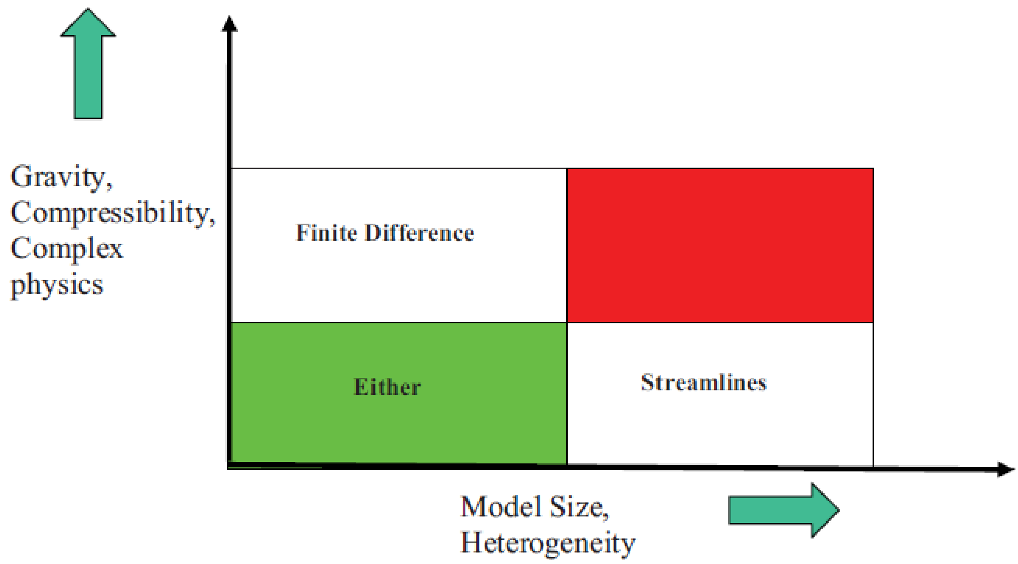

Figure 1.2.7. A schematic showing applicability of streamline vs. finite-difference simulation.

Time of flight (TOF) - Short injector–producer time of flight indicates ineffective injection and potential for water recycling. (effective swept TOF > 1000 days; early breakthrough TOF < 1000 days)

Streamline velocity - There is a relationship between the streamlines and potential, as obtained below for single-phase Darcy's law:

$$\vec{u} = -\frac{1}{\mu}\overrightarrow{k} * \nabla\phi \qquad (2)$$

where ϕ - denotes the fluid potential (the pressure),

$\vec{u}$ - the Darcy velocity,

μ – viscosity,

$\overrightarrow{k}$ - the dispersion tensor. *(Datta-Gupta et al., 2007)*

Distance between wells – The potential for the quadrant is sum of the potentials for a well at (x_1, y_1) and image wells at (x_1, - y_1), (- x_1, y_1), and (- x_1, - y_1).

$$\Phi = \frac{Q}{4\pi h} ln((x - x_1)^2 + (y - y_1)^2) + \frac{Q}{4\pi h} ln((x - x_1)^2 + (y + y_1)^2) + \frac{Q}{4\pi h} ln((x + x_1)^2 + (y - y_1)^2) + \frac{Q}{4\pi h} ln((x + x_1)^2 + (y + y_1)^2) \quad (3)$$

where Q – flow rate of fluid,

x, y - coordinates of the point where the potential is being evaluated,

$x_{1,}\ y_1$ - coordinates of the well.

(Datta-Gupta et al., 2007)

1.2.4. Subsurface Hydraulics - Basniev

In the next research, the interference for two wells has been considered, however, in the following chapters, this will be investigated for multiple wells. This study examines the field of subsurface hydraulics and fluid filtration, with a particular focus on Darcy's law and modeling of percolation flows. It then presents the theoretical foundations of percolation in various reservoirs. Basniev (1986) shows how to solve filtration problems analytically using the theory of functions of complex variables. Then, the direction and velocity of the flow are studied because of the analysis performed on streamlines and isopotential *(Basniev, 1986).*

1.2.5. Toe-to-heel air injection well selection considerations

Toe-to-heel air injection (THAI), a thermal method of EOR process, and the impact of well selection configurations on the recovery process are the discussed in *(Xia, Greaves, & Turta, 2002)*'s study. In terms of well selection criteria, these are some important points. study focuses on toe-to-heel air injection (THAI), a thermal method of EOR process and how well selection configurations affect the recovery process. Here are some key points in terms of well selection criteria.

- Reservoir parameters - When the oil viscosity is relatively low (probably less than 5,000 mPa·s) and the pay thickness of the layer is relatively thin (probably less than 8–10 m), the process might be able to start.

- Injection technology - The combination of horizontal producer wells (HP) and horizontal injection wells (HIHP) was found to be the most efficient configuration for achieving quick startup and stable combustion front propagation.
- Well design and location - The ISC (In-Situ Combustion) method should start from the top with a series of vertical injectors with spaced apart from each other. Fewer injectors are necessary since each horizontal producer will serve as an injector upon reaching the ISC front. For this purpose, horizontal wells will be used only for injections. Compared to SAGD and Vapex, the number of wells required for a fixed pattern area for peripheral line transmission operation using THAI (which is equal to the product of the well spacing and the well length) is reduced by about half; each sample area consists of two wells for SAGD and Vapex and only one well for THAI.

Research has shown that horizontal injection wells, in combination with horizontal producers, provide efficient combustion initiation and propagation under laboratory conditions. However, the practicality of using horizontal injection wells in the field remains a significant safety and operational challenge. Experiments have been limited to specific heavy oils and controlled conditions, leaving uncertainty about performance in more heterogeneous or diverse reservoirs. In particular, the ignition delays at vertical injectors and low initial temperatures highlight the need for improved start-up techniques. These criteria are not universal and are specific to this intervention method *(Xia, Greaves, & Turta, 2002).*

1.2.6. Fuzzy logic candidate-well selection process

The work of Zoveidavianpoor, Samsuri, and Shadizadeh (2012) discusses the application of fuzzy logic (FL) in the candidate-well selection process for hydraulic fracturing (HF), a crucial technique for oil and gas well stimulation. The authors investigate the use of FL to control the complexity and uncertainties associated with the well selection procedure.

The authors demonstrated how to use FL to manage uncertainty in the decision-making process to increase the accuracy of well selection for HF treatment. They emphasized how FL could be used in conjunction with other AI techniques to optimize the selection of candidate wells while considering several factors at once. It is especially beneficial to use FL, especially Type-2 Fuzzy Sets (T2 FSS), to capture inherent uncertainty. The screening methods developed are as follows:

- Reservoir Pressure - Reservoir pressure is a key factor in determining the ability to efficiently inject fluids. Higher reservoir pressure wells are thought to make better fracturing candidates.
- Permeability - Formation permeability affects fluid injection processes as higher permeability allows effective fluid injections.
- Skin Factor - The skin factor measures the damage to the wellbore and the flow resistance near the well. A low skin factor indicates good reservoir connectivity, making the well a better candidate for injection.
- Well productivity - When reservoir permeability and reservoir pressure are favorable, wells with low initial productivity may be suitable candidates for fracturing recovery.
- Wellbore condition - Selecting wells for fracturing, the wellbore's physical state, including well integrity, is crucial. Wells with good structural integrity are preferred for fracturing treatments *(Zoveidavianpoor, Samsuri, & Shadizadeh, 2012).*
- Proppant transport and fracture closure - The key to successful fracturing is the ability to move proppant efficiently and keep the fracture closed. Wells where proppant can be adequately placed and fracture control can be achieved are preferred *(Li, He, Wu, & Liu, 2023).*

According to *(Utegalyev et al. 2006)*, they were able to carry out a very successful stimulation campaign by utilizing a multidisciplinary team, developing, and focusing on variables that could be directly impacted (such as the operational aspects of the process). It is important to remember that this method worked best in cases where there was no data available.

The authors stress the ability of fuzzy logic to lower uncertainty when choosing candidate wells for hydraulic fracturing. In order to ensure more effective hydraulic fracturing operations, their work attempts to optimise the selection of injector wells. However, the criteria of the study are few and imprecise *(Zoveidavianpoor, Samsuri, & Shadizadeh, 2012).*

(Smith. 2006) proposed that successful candidate-well selection should be based on three distinct scales: regionalized, neighborhood, and localized (Table 1.2.4).

Table 1.2.4. Scaled candidate-well selection considerations.

Scale	Variables
Regional (*Macro*)	Reservoir Heterogeneity Reservoir Continuity Geographical Information System (GIS) Gathering and Production (GAP)
Neighborhood (*Meso*)	Offset Well Performance Drainage Shape and Area Areal Connectivity Publicly Available Data
Localized (*Micro*)	Reservoir Characteristics Pressure Transient Analysis Production History Matching Mechanical Integrity

The wells were ranked using a weighted parameter approach in a preliminary candidate-well selection methodology *(Moore and Ramakrishnan, 2006).* Table 1.2.5 contains a list of those parameters *(Smith. 2006).*

Table 1.2.5. Weighted parameters approach used for preliminary candidate-well selection.

Percentage	Parameters
20	Kh (perm. times net pay)
20	Cumulative production
20	Previous treatment (proppant/m net pay)
10	Cumulative production time
15	Gas saturation
10	Current performance
5	Recovery ration

They emphasize the importance of accurate candidate-well selection for hydraulic fracturing (HF). Proper well selection improves the success rate of fracturing treatments, which is essential for increasing production in low-permeability reservoirs. Conventional methods for candidate-well selection include assessing the skin factor, reservoir permeability, and well history. These methods have been widely used and form the backbone of most HF treatment programs. However, the study suggests that these conventional techniques can be enhanced by integrating advanced technologies like Artificial Intelligence (AI) and Fuzzy Logic (FL) for better accuracy in well selection. The article identifies that there is no unified approach for selecting candidate wells universally across all geological settings. Different reservoir types, well conditions, and economic factors must be accounted for to optimize well selection *(Zoveidavianpoor, Samsuri, & Shadizadeh, 2012, p. 55).*

1.2.7. Artificial neural networks to identify candidates

In this study, the Red Oak Field's wells that require restimulation or recompletion are identified using Artificial Neural Networks (ANNs). By using machine learning techniques to forecast the possibility of production enhancement through restimulation, the study aims to optimize selection. Here are the key achievements:

ANN development – In order to forecast post-recompletion production, the study created an ANN model. A dataset of roughly 25 well records from the Red Oak field was used to train the model. Geographical location, reservoir pressure, perforation details, production rates, initial completion, and stimulation data were among the well attributes that were used in the ANN model. The model successfully predicted the post-recompletion production of the wells, with an R^2 value of 0.99, indicating excellent accuracy in forecasting well performance.

Well selection criteria for restimulation – The ANN was trained to identify wells with the highest potential for production enhancement through restimulation. The input data included well location, initial production rates, reservoir pressure estimates, and perforation information. The research indicated that 30% of the wells displayed adequate potential for economically viable recompletion, while 50% showed only modest improvement potential, and 20% were expected to face a decrease in production after restimulation.

Optimization of restimulation process – The authors used sensitivity analysis within the ANN to evaluate how different parameters (such as proppant weight, stimulation volume, and fluid type) influenced production. The sensitivity analysis indicated that larger restimulation volumes and the use of foam fluids resulted in the highest production increase. The ANN model identified specific characteristics that made a well a better candidate for restimulation. For instance, wells with smaller initial completion volumes were more likely to show better refracture potential, which was consistent with conventional reservoir engineering logic.

Geographical and spatial analysis – The wells' geographic locations were also taken into account by the ANN analysis, which revealed that some wells in the field's interior regions had greater potential for restimulation. This analysis was critical for field management, helping to optimize well spacing and placement for maximum production.

In this study, the author utilized advanced ANNs to identify wells suitable for restimulation in the Red Oak field. They provide a methodology for predicting the post-recompletion production potential of existing wells. The research focused on optimizing well selection based on key reservoir parameters, including reservoir pressure, permeability, and wellbore condition, while also considering geographic location. However, despite advances in predicting well performance and improving recovery decisions, there remains a gap in the methodology for well selection criteria that can be universally applied to all reservoirs. While the study provides significant insights into the Red Oak field, there is no comprehensive, generalized framework for well selection criteria applicable to broader areas with varying geological conditions and reservoir characteristics. For example, the time efficiency of the well selection process could be enhanced by expanding the decision-making criteria to include real-time data analysis and automated algorithms. This can significantly reduce the need for time-consuming manual assessments. These improvements will not only simplify the selection process but also result in significant time and cost savings for operators in a variety of reservoir conditions *(Shelley, 1999).*

1.2.8. Refracturing well selection study

The authors *(Kong, Ostadhassan, Tamimi, Samani, & Li, 2019)* performed review of refracturing technology and its application in unconventional reservoirs, particularly focusing on the criteria for selecting candidate wells for refracturing. They discussed how refracturing has evolved as a key method to enhance production, particularly when hydraulic fracturing operations have declined or underperformed. The authors reviewed various methods for selecting wells that could benefit from refracturing and highlighted the technical procedures that are critical for the success of the treatment. Here are the highlights:

Reservoir parameters - Higher permeability is typically preferred for well selection as it allows for better fluid injection and production.

Well selection methods:

Statistical analysis - This method involves data-driven approaches that quickly identify underperforming wells. Simple statistical models are applied to historical production data to screen wells and highlight candidates with the potential for restimulation.

(Roussel et al., 2013) proposed a systematic method to evaluate the refracturing potential of wells that five dimensionless groups could be developed to quantify the properties impacting the refracturing performance. As shown in (Figure 1.2.8), five dimensionless criteria are stress reorientation numbers (Πpro, Πmech), completion quality numbers (F , Fuo//Dip), reservoir depletion number (Rdp), and production decline number (Dpd). First, stress reorientation numbers are analyzed to evaluate the potential for the alteration of stress orientation in a formation zone, which is associated with a higher reservoir recovery as well as unanticipated hydrocarbon. Then, a completion number is calculated and divided into two sets, separated by 0.1 increment, in which the smaller group would represent the lower production decline number and end in refracturing while the larger group having the lower depletion number representing the candidates for refracturing.

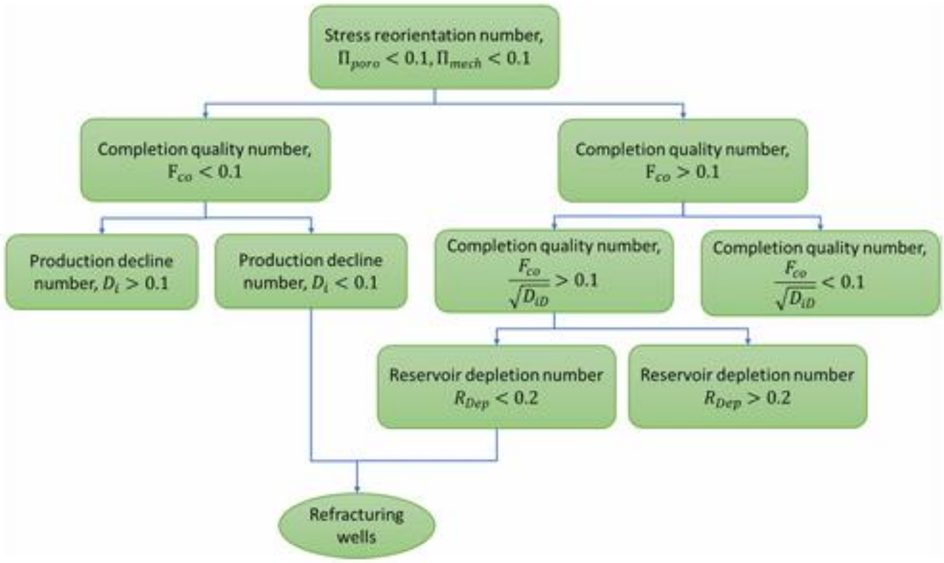

Figure 1.2.8. Decision algorithm for selecting the candidates of refracturing wells.

Advanced Screening- ANN and Genetic Algorithms (GA) are used to predict well performance based on a broader set of parameters. These advanced methods consider not only technical data (e.g., permeability and formation pressure) but also historical performance and economic factors, making them more accurate than traditional methods.

Production type-curve matching - This technique involves matching production curves to understand the relationship between well performance and reservoir characteristics. The method is especially useful for identifying high-permeability wells that are more likely to benefit from refracturing, as they show higher potential for production enhancement

Economic and operational considerations - Economic factors were also considered, particularly in times of low oil prices, where refracturing can be a more cost-effective alternative to drilling new wells.

The study included case studies from successful refracturing operations, such as those in the Bakken Formation and Barnett Shale. These studies demonstrated the effectiveness of the selection criteria and the significant economic advantages of refracturing compared to drilling new wells. While the study provides valuable insights into refracturing techniques and well selection criteria, there are some gaps that need to be addressed to improve the applicability of the methodology across different reservoirs. The study primarily focuses on shale reservoirs and unconventional formations. One significant gap is the lack of a universal framework that can be applied to all types of reservoirs, particularly those with varying geological conditions and fluid properties. Customizing the selection criteria for different types of reservoirs remains a challenge. While the study mentions economic factors, there is no specific mention of time-saving techniques for well selection or operational procedures. In practice, the process of well selection and refracturing treatments can be time-consuming, and more automated or real-time decision-making models could save both time and costs. The review discusses several methods for evaluating well performance, but it suggests that data-driven approaches, such as Artificial Intelligence (AI), could significantly enhance the accuracy and efficiency of the well selection process. Despite mentioning AI, the application of these emerging technologies is still underexplored and would need further research to develop more robust models for well evaluation *(Kong, Ostadhassan, Tamimi, Samani, & Li, 2019).*

1.2.9. Well screening criteria of Heydarabadi's study

Criteria for candidate well selection based on Heydarabadi, (2010)'s work:

Reservoir permeability - Reservoirs with permeability less than 1 md (milliDarcys) are usually considered for hydraulic fracturing. Reservoirs with permeability above 10 md are generally more suitable for other stimulation methods like matrix acidizing. Permeabilities between 1 and 10 md require further evaluation for determining the most appropriate stimulation method.

Reservoir skin factor - A positive skin factor typically indicates that the well requires hydraulic fracturing. A negative skin factor, which suggests that the formation's permeability is less than that of the near-wellbore region, may still be suitable for fracturing, depending on other conditions such as the presence of natural fractures or previous treatments.

Production history of the well - The production history is used to assess the well's potential for improvement through hydraulic fracturing. Wells with significant production declines may be considered for fracturing if the decline is caused by damage to the near-wellbore region. Comparing the production performance of the candidate well with offset wells can provide additional insights.

Oil/gas in place volume, hydrocarbon saturation, and reservoir pressure - For fracturing to be economically viable, the oil/gas in place volume, hydrocarbon saturation, and reservoir pressure must be sufficient. These parameters help determine if hydraulic fracturing will lead to a positive economic outcome by increasing recovery.

Containment of hydraulic fracture - The ability of the formation to contain the hydraulic fracture is a critical factor. Poor fracture containment can lead to loss of fluid or communication with unwanted zones, such as water-bearing layers.

In-Situ stress profile - The minimum horizontal stress in the reservoir must be accurately measured, as it plays a major role in fracture propagation. Methods such as core analysis, micro-frac tests, and dipole sonic logging are used to gather data on in-situ stresses.

Table 1.2.6 summarizes the evaluation of the criteria presented for the selection of a candidate well for hydraulic fracturing *(Heydarabadi, Moghadasi, Safian, & Ashena, 2010)*. The well selection criteria established in the Heydarabadi, (2010)'s study help guide the decision-making process for selecting the most appropriate wells for hydraulic fracturing. However, there are still some gaps in the existing approach. Current criteria primarily focus on individual well parameters without fully considering the interference between wells or the integration of real-time operational data. As such, future studies should focus on developing comprehensive, real-time well selection frameworks that incorporate dynamic changes in reservoir conditions and operational efficiency. Further research into more advanced data-driven models and the integration of machine learning for real-time well monitoring would allow for more efficient, cost-effective, and timely decision-making in well selection for hydraulic fracturing.

Table 1.2.6. Evaluating candidate well for hydraulic fracturing.

Criteria	Well A	Well B
Containment of the Hydr. Frac. & In-situ Stress Profile	Non-Conclusive	Good
Permeability Range of the Formation	Bad	Fair
Oil/Gas in Place Volume, Hydrocarbon Saturation and Reservoir Pressure	Good	Good
Production History of the Well	Bad	Good
Reservoir Skin Factor	Non-Conclusive	Non-Conclusive
Modelling Production Performance of the well	Marginal increase in productivity	Considerable increase in productivity

The most important parameters in selecting a well for hydraulic fracturing are reservoir permeability, accurate stress profiling, and fracture retention assessment. Based on the results in Table 1.2.6, well B is a suitable candidate for hydraulic fracturing because all criteria support it as a candidate. On the other hand, most of the criteria presented do not support well A as a candidate for hydraulic fracturing (*Heydarabadi, Moghadasi, Safian, & Ashena, 2010).*

1.2.10. Well screening criteria of CO2 injection on the Jurong oilfield

This study addresses the problem of optimal well placement for production optimization in oil reservoirs. The main goal is to determine the best locations for new water injection wells to maximize the net present value (NPV) of the reservoir over its lifetime while respecting constraints such as a fixed total injection rate. The challenge lies in the fact that well locations are usually discrete variables, which makes gradient-based optimization methods difficult to apply directly. To overcome this, the authors propose an innovative approach where they initially place an injection well in every grid block that doesn't already contain a producing well. Then, through a gradient-based optimization algorithm, they adjust the injection rates of these wells. Wells whose injection rates are driven down to zero are effectively eliminated from the system, thus optimizing both the number and location of wells. The NPV formulation accounts not only for oil revenue and water disposal costs but also for the drilling cost of each well, which encourages the reduction of unnecessary wells to save costs.

The optimization is performed using a steepest ascent method. It adjusts injection rates iteratively, ensuring that the sum of all injection rates remains constant (fixed total injection). At each iteration, only one well can be eliminated by driving its injection rate to zero, which gradually leads to an optimal subset of wells. The method was tested on two cases: a homogeneous reservoir and a heterogeneous reservoir. In the homogeneous case, the algorithm successfully identified a single injection well placed at the reservoir's center, which matches intuition. There is a single injector left at the end of the optimization process, and it is at the center of the reservoir in gridblock as shown in Figure 1.2.9. NPV as a function of the iteration number is shown in Figure 1.2.10. In the more complex heterogeneous reservoir, it also converged to a single well, though in a less obvious location due to permeability variations and flow directions. The reservoir contains two producing wells at the locations shown in Figure 1.2.11 which also depicts the known permeability distribution. Figure 1.2.12 shows the net present value as a function of the iteration number (Wang, Li, & Reynolds, 2007).

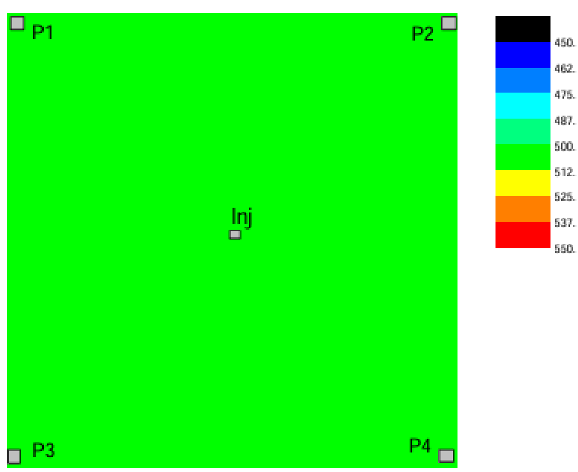

Figure 1.2.9. Well placement optimization results for homogeneous reservoir.

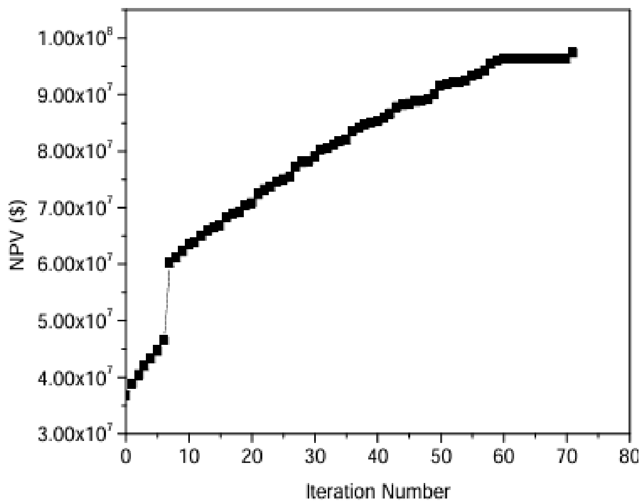

Figure 1.2.10. Net present value with iteration for homogeneous reservoir.

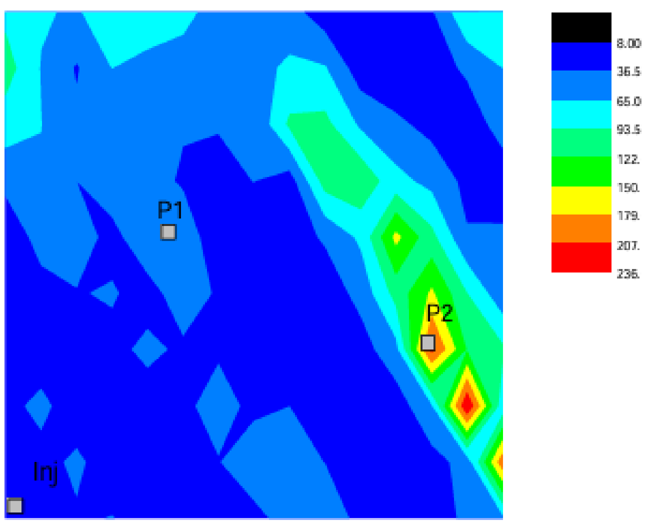

Figure 1.2.11. Well placement optimization results for heterogenous reservoir.

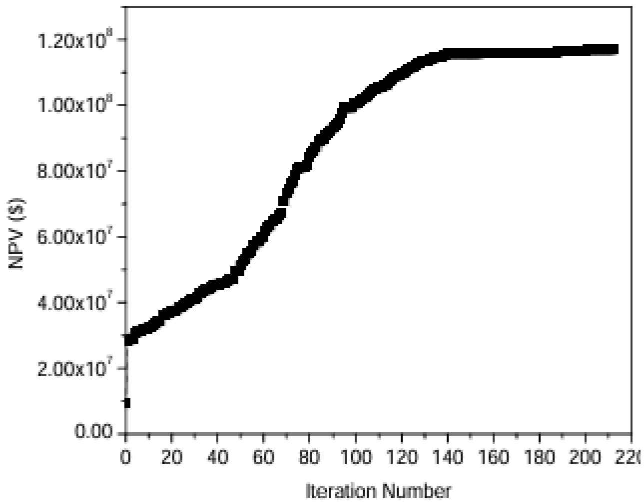

Figure 1.2.12. Net present value with iteration for heterogenous reservoir.

Regarding well selection, the key aspects are:

- Starting with an injection well in every possible grid block creates a large initial candidate set.
- Through optimization, the injection rates are redistributed, gradually eliminating less effective wells.
- The final well configuration balances maximizing oil production and minimizing drilling costs.
- Only one well is removed per iteration, which makes the algorithm straightforward but potentially slow when starting with many candidate wells.

Despite its promising approach, the study identifies some gaps and limitations such as:

The elimination of only one well per iteration leads to slow convergence when dealing with many initial wells, making the method inefficient for large-scale problems.

The approach is demonstrated only in two dimensions (2D), which limits its immediate applicability to real three-dimensional reservoirs.

There is a risk of the algorithm getting stuck in local optima, especially in heterogeneous reservoirs with complex flow patterns.

The study lacks comparison with other well placement optimization methods, which would help assess the strengths and weaknesses of this approach more thoroughly.

The model considers only two-phase (oil-water) flow, while actual reservoirs often involve more complex multiphase interactions and additional physical phenomena *(Wang, Li, & Reynolds, 2007).*

1.2.11. Well screening criteria for gas injection

In Thomas (1998) study, He suggested screening criteria with which to evaluate reservoirs appropriate for gas injection EOR. He pinpointed six parameters governing the effectiveness of gas injection given multiphase flow complexity in porous media: phase behavior, interfacial tension (IFT), mobility effects, pore size distribution, gravity, and wettability. Thomas (1998) developed a quantitative ranking framework that incorporated reservoir size and fluid viscosity in addition to gas cap presence, reservoir orientation plus economic and reservoir-specific characteristics. Because it ends in a maximum score of 150, his ranking system assigns scores to each criterion, which helps prioritize reservoirs for the feasibility of gas injection EOR. Specifically, reservoirs perform best in cases where they have low oil viscosity (<0.5 cP), homogeneous pore size distribution, as well as low gas/oil IFT (<0.2 dynes/cm). These reservoirs lack gas caps also, which leads to successful field applications. Using three sample reservoirs, was validated on Thomas (1998) framework and did show that higher-ranking reservoirs demonstrated both technical success and economic success. However, poorer displacement efficiency was demonstrated by lower-ranking reservoirs, so their development was deemed uneconomical.

Despite the robustness with this selection approach, gaps remain. Laboratory measurements as well as flood data do largely inform the study though they may not fully capture heterogeneity of field-scale reservoirs. The ranking system uses weights that are rather arbitrary. It also does fail to incorporate uncertainties that are explicitly related to reservoir heterogeneity or operational constraints such as injection strategies and surface facilities. Additionally, although Thomas (1998) addresses the role of gravity and mobility, more research is necessary to fully understand how these parameters interact dynamically in complex reservoirs, especially in fractured or highly heterogeneous formations.

While this study provides a useful framework for selecting wells for EOR through gas injection, there are significant gaps in the effectiveness and applicability of existing criteria. First, most existing models are based primarily on laboratory-scale core flood experiments and limited field work, which do not fully capture the complexity and heterogeneity of real reservoir conditions. This raises questions about the validity and scalability of selection criteria in applying them to different geological settings. Second, most existing criteria prioritize static reservoir and fluid properties - such as viscosity, pore size distribution, and interfacial tension - but do not fully consider dynamic operational factors such as injection strategies, well placement optimization, and surface infrastructure constraints. These factors and the interactions between reservoir properties can significantly affect injection performance, but they have not been adequately explored in selection methodologies. Additionally, the existing criteria cannot be universally applied to every well *(Thomas, 1998)*.

1.2.12. Water injection efficiency criterion for oil sands

Lin (2017) developed a quantitative index to measure the efficiency of water injection stimulation in heavy oil sands reservoirs, specifically for use in SAGD well pairs in Xinjiang, China. They addressed the issue of determining whether the injection process creates a well-developed, high-permeability zone between the injection and production wells before steam circulation. This criterion is based on the Contact Parameter (CP), which represents the level of hydraulic connection between two wells, the injection and production wells. CP is a quantity ranging from 0 to 1, calculated based on the distribution of pore pressure around the wells. This pressure distribution is modeled using finite element methods, geomechanical and petrophysical properties. The goal was to determine whether a well-developed, high-permeability zone is created between the two wells during injection. A certain critical level of CP, the Contact Parameter Threshold (CPt), has been defined for various reservoir types. When this threshold is reached, hydraulic connection is established, and water injection is effectively completed. Thus, when the CP is equal to or higher than the CPt level, the pressure responses between wells become more closely coupled and the injection rate increases dramatically. The parameters that play a key role in the criterion include the porosity, permeability, bitumen and sediment content of the reservoir, as well as its mechanical properties - young's modulus, friction angle, cohesion and expansion angle. Operational parameters such as injection pressure and volume are also considered in the calculation of this criterion.

Thus, the criterion presented by Lin (2017) is a tool that quantitatively assesses the effectiveness of water injection and allows predicting the time of connection between wells. It provides field engineers with a practical way to monitor the progress of the injection process and develop optimal injection plans. However, despite these advances, there are a number of limitations recognized by the research. Furthermore, the model does not capture well heterogeneities such as natural fractures, caves, or sand channels that can significantly affect injection. Also, the application of CP requires accurate geomechanical and injection data, which may not be possible for all reservoirs *(Lin et al., 2017).*

CHAPTER II: METHODOLOGY

2.1. Introduction to methodology

In this chapter, we will describe the research approach used to develop the criteria for selecting injection wells, which can effectively impact the productive formation in order to enhance oil recovery. This includes discussing the data collection methods and analytical techniques used in this study.

2.2. Data collection methods

The data collection for this study is based on two major categories: production well data and injection well data. Below is a detailed description of the required data:

1. Geological map of the studied zone
2. Time period of data collection - The time period for data collection is a crucial factor as it influences the well-performance temporal analysis
3. Production data (oil, water, gas) - This data is necessary for evaluating the performance of production wells and assessing the impact of injection on production rates. Well location data is crucial for analysis of well performance and for calculating interference effects between wells.

   Required data:

   - Well numbers for the production wells active during the study period.
   - Flow rates of oil, water, and gas during the study period.
   - Well coordinates (x, y) to track the exact locations of the wells within the field.
   - Filter thickness: This refers to the pay zone thickness, which affects well productivity.
   - Well operating days: The number of days the production wells were operational during the study period.
4. Injection data - This data is critical to assess the performance of injection wells and to ensure that the injected fluid reaches the desired zones efficiently in the reservoir, optimizing the injection process.

   Required data:

   - Well numbers for the injection wells used during the study period.

- Actual injection volume (in tons or m^3) of injected fluids.
- Coordinates (x, y) of the injection wells on the development map to locate them accurately.
- Working days of the injection wells: the number of operational days during the study period.

These criteria can be applied to any reservoir for well selection and optimization purposes.

2.3. Analytical techniques and tools

The preceding methodology section described the data collection methods, while this section outlines the analytical techniques to be employed in developing the injection well selection criteria for enhancing oil recovery. In this study, seven criteria were used to select injection wells to increase oil production. MATLAB will be used to analyze the data to evaluate and develop the best injection well selection strategies.

Here, seven criteria were used to select injection wells, and they are as follows:

1. Geological conditions – The geological map of the studied block will play an important role in understanding the distribution of the reservoir and identifying key geological features. This map will illustrate the development of the productive layer of the field by providing a visual representation of the locations of the wells, as well as the boundaries of the investigated zone. Important features that affect fluid movement and reservoir characteristics, like layer boundaries, faults, and fractures, will be highlighted. The target horizon will be chosen by assessing the layers that exhibit significant fluid production potential and stability based on the geological map. Existing wells, productivity in various layers, and other geological characteristics like porosity, permeability, and fracture distribution will all have an impact on the selection process. The aim is to identify the most promising horizons for injection well placement to optimize oil recovery. How well the injected fluid spreads depend on the reservoir's heterogeneity, which includes differences in permeability and porosity. The geological conditions of a reservoir can vary significantly; however, the primary parameters that must be considered here are the permeability and porosity of the rock layers. The values of these two parameters, when within their average ranges, are sufficient to enhance oil productivity. Furthermore, the inclination angle and thickness of a productive layer must be

compatible with one another; for instance, during injection processes, reservoirs that are horizontal or nearly horizontal tend to exhibit greater recovery efficiency.

2. Production rate and reservoir condition – This analysis is essential to spot well performance trends, understand fluid dynamics, and optimizing the injection process for enhanced oil recovery. The analysis of well data will be carried out to assess the performance of each well. During the study, current data on production and water breakthrough, as well as the formation's water acceptability capacity is collected for each well. Specifically, the study will evaluate the flow rates of the wells to determine the production levels of oil and water. Historical data on production, injection rates and watercut will be collected for each well in the study. In addition, the parameters of the formation fluid and oil density, as well as the filter length, are considered as part of the well's given characteristics. These parameters influence fluid movement through the reservoir and impact the overall efficiency of the injection and production processes. Additionally, the watercut for each well will be analyzed to quantify the proportion of water relative to the total production. for example, in a case studies show that a high filtration rate causes the injected substance to move toward production well without effectively sweeping the oil. This phenomenon occurs due to rapid breakthroughs caused by pressure differentials, which subsequently reduces sweeping efficiency. The injection fluid must sweep the oil toward the bottom of the well as effectively as possible. In certain cases, selecting production wells with low oil output or those that are already waterlogged for conversion into injection wells can be a time-saving and cost-effective approach. This approach lowers operating expenses related to the drilling of new injection wells while simultaneously optimizing well utilization.

3. Well location – The efficiency of fluid injection is directly impacted by well location. Make sure the injection well is positioned to have the greatest possible effect on the intended reservoir. There are considered variables including the separation between injection and production wells, the distance to production wells, and potential influence zones. The distance between injection and production wells is not calculated in the usual way, but as the distance along the flow lines from the injection well to the production wells, and the visualization of potential zones of influence is considered. The distance between the injection well and the production well should be sufficiently far to ensure effective displacement, but they should not remain outside each other's influence zone. The well coordinates are matched with the

geological map to ensure accurate placement and alignment of the wells within the reservoir, facilitating a better understanding of well performance and fluid movement. Information about the coordinates of the wells should be taken from the point where the wellbore enters the productive layer. In offshore conditions, the accuracy of the coordinate should be consistent with the geological map of the productive layer, which helps to better understand the performance of the wells and the movement of the fluid. Distance between the wells is critical parameter. For example, If the wells (injection and production wells) are too close to each other's, it leads to rapid breakthroughs and low recovery, while excessive distance results in reduced productivity or even may lead to ineffectiveness.

4. Modeling – By using the MATLAB software, the data is processed, and the results are comprehensively analyzed through a software module created to model fluid flow in the formation based on the collected data and verify compliance of wells with selection criteria. The efficiency of various injection scenarios is assessed using modeling methods based on the theory of complex variable functions. An algorithm is developed to process the data, and the results are thoroughly analyzed. Predictions will be made regarding the efficiency of different injection scenarios using hydrodynamic modelling. This aids in understanding the relationship between the reservoir and the injected fluids as well as optimizing injection settings. These reservoir modeling software tools can be used: ECLIPSE, CMG (IMEX, GEM, STARS), tNavigator, MATLAB etc. The construction of the current state model is based on mathematical formulas, which constitutes the process of modeling. Recent studies have focused on calculating the interference or influence between two wells, as discussed in chapter I, subchapter 2. However, such calculations may lead to incorrect or unrealistic results in some cases, as simply calculating how two wells interact with each other to study the underground processes in the industry can lead to significant errors.

The problem is solved by considering the interference between wells. The visualization of the distribution of the current hydrodynamic state in the studied area is based on mathematical formulas that form the process of building a model that considers interference between wells. The research outcomes include formulas that enable calculations for each cell within the grid superposed the studied area of the field.

The values of the stream functions and potentials are F_1 and F_2 respectfully, the characteristic function of the flow or the complex potential F, the modulus of the filtration rate

W, gradients of $F(x,y)$, $F_1(x,y)$, and $F_2(x,y)$ respectively, $grad(F)$, $grad(F_1)$ and $grad(F_2)$. Injecting wells are taken as sources (Q < 0), and production wells are taken as sinks (Q > 0). The task is solved in the cartesian (xk, yk) and polar coordinate (r,φ) systems:

$$z_k = x_k + i \cdot y_k = r_\kappa \cdot e^{i \cdot \phi k} \tag{4}$$

Complex potential:

$$F = F_1 + i^* \cdot F_2 \tag{5}$$

The above-mentioned hydrodynamic parameters are determined based on the principle of superposition to consider the simultaneous effect of each cell of the grid. According to the principle of superposition, which is applied to points considered as the source and sink of a layer operating simultaneously from same formation:

$$F_1 = \sum_{i}^{n}\sum_{k=1}^{K}\sum_{j=1}^{J}\frac{q_i}{2\pi}\ln(r_i(\mathrm{k},\mathrm{j})) \qquad F_2 = \sum_{i}^{n}\sum_{k=1}^{K}\sum_{j=1}^{J}\frac{q_i}{2\pi}\varphi_{i,j} \tag{6}$$

Modules of filtration rate:

$$W = \left|\frac{dF}{dz}\right| = \sum_{i}^{n}\sum_{k=1}^{K}\sum_{j=1}^{J}\frac{q_i}{\pi\, r_i(\mathrm{k},\mathrm{j})} \tag{7}$$

The gradient of the function $F(x,y)$:

$$grad(F) = (\partial F(x,y)/\partial x) \cdot i_v + (\partial F(x,y)/\partial y) \cdot j_v \tag{8}$$

Where:

z_k, x_k, y_k – k the coordinates of well number κ expressed in complex and real numbers, respectively.

$grad(F)$, $grad(F_1)$, $grad(F_2)$ - Gradient functions, which indicate the direction of fluid flow in the formation, are determined by the difference between the values characterizing

consecutive streamlines.

$\kappa = 1, \ldots n$ - the number of wells in the field of application.

i^* – imaginary unit.

$q_к$, F_1, F_2 – flow rate of the k-th well (fluid per 1 meter of well filter), flow and potential function, respectively.

$r_к$, $\varphi_к$ – the distance and polar angle from well number $к$ to the starting point of the coordinate system, respectively.

The hydrodynamic characteristics mentioned above are established based on the principle of superposition, considering the simultaneous influence of both sources and sinks within the reservoir. To perform the calculations, initial input data includes the current production rates of wells, their injectivity, and the coordinates (*xi, yi*) of each of the n wells operating in the target horizon of the area. The well coordinates are necessary for calculating the distance between any grid cell with index *k, j* to the i well and the polar angle that determines the position of the radius vector in relation to the unit basis vectors i_v, j_v. Considering the presence of interference between wells, which are considered as source and destination points, methods for diagnosing the current state of the productive layer in the area where the wells are located have been developed. This framework enables the digital visualization of streamlines and equipotential lines, reservoir flow rates and their gradient vectors, zones of pressure variation, and other key reservoir characteristics, all represented through a color-coded scale:

Distance between well (xi, yi) and cell (x_j, y_j) in Cartesian coordinates:

$$r_{i,j} = \sqrt{\left(x_j - x_i\right)^2 - \left(y_j - y_i\right)^2} \tag{9}$$

Polar angle:

$$\phi_{i,j} = \frac{(y_j - y_i)}{(x_j - x_i)} \tag{10}$$

Complex potential is defined as:

$$F_j = \left(F_{j,1} + i \cdot F_{j,2}\right) \tag{11}$$

i- corresponds to well number

j- corresponds to the distance to each cell.

r- is the radius vector,

φ- is the polar angle

Filtration speed:

$$w = \frac{q_i}{2\pi r_{i,j}} \tag{12}$$

The initial data to implement the calculations include the current production values of each of the *n* wells operating from the target horizon of the field, the well injectivity of the injection wells, and the coordinates (x_i, y_i). Well coordinates i are used to calculate the distance from each grid cell (i_v, j_v) with *j* index to well number k, which is the polar angle that determines the position of the radius vector with respect to the unit vector. Taking into account the interference between wells, which are considered source and sink points, methods have been developed to diagnose the current state of the productive layer in the area where the wells are located. This framework allows for digital visualization of flow and equipotential lines, fluid flow velocities in the productive formation and their gradient vectors, pressure change zones, and other key hydrodynamic features, all represented by a digital color scale.

5. Choice of injection Technology – Selecting the appropriate injection technology is crucial for maximizing oil recovery. The type of fluid present in the layer, as well as the fluid previously injected into it, will be analyzed. Based on hydrodynamic distribution, we determine the impact method to be applied to the formation and the type of fluid to be injected through a screening process. Data on different injection fluids (e.g., water, CO_2, polymers) and injection rates will be gathered. The appropriate fluid to be injected will be selected, taking into account the current reservoir conditions. For instance, if the flow rate is high or if there is excessive fluid flow into a specific zone, that area can be treated with a surfactant to let's call block it. Such methods of intervention are widely utilized in industry.

6. Economic calculations – Economic considerations are essential for selecting the optimal injection well and method. Calculations will be conducted to determine which fluid will be injected into the reservoir, which well will be used for injection, and whether a new well will be drilled or an existing well will be shut down. One of the fundamental questions in reservoir development is how much capital is invested and what economic return can be expected. This evaluation includes considerations such as whether new wells should be drilled for injection or existing wells can be utilized, along with estimates of the recoverable oil volume and other related calculations. As we know, drilling new injection wells is a process that requires a lot of

resources and time, and this results in uncertainty about the oil revenue we will get *(El-Bagoury, 2024).*Instead, in this case, it is proposed to establish injection well selection criteria and convert existing wells, for example, a well with weak oil yield, into an injection well. This is both profitable and timesaving. Data on the cost of injection fluid, well operating costs, and projected oil recovery will be gathered.

7. Monitoring and adjustments – According to the predetermined criteria, the reservoir was subjected to the planned intervention after all necessary calculations were carefully completed. After the implementation of the intervention, detailed observations were conducted, and the reservoir's response was carefully recorded to assess the efficacy of the employed method. Once the injection well was put into operation, a comparison between the reservoir's condition before and after the intervention was made. Periodically monitoring of well performance and reservoir conditions was then started to ensure optimal performance. This allows for real-time adjustments and strategic refinements based on the observed results. In addition, any anomalies or discrepancies identified during monitoring are promptly resolved, and the required corrective actions are implemented to ensure operational efficiency and guarantee the enhanced oil recovery strategy's long-term success.

CHAPTER III: The Practical application and analysis for X fields

3.1. The Practical application and analysis of the criteria

Hydrodynamic maps were prepared using an algorithm applied to current data of the Y horizon of the X field, 120 km east of Baku in the Caspian Sea. For field X, the following information was collected: production flow rate, days of operation, well numbers for the productivity of production and water injection wells, and the length of the filter zone (pay zone thickness) for the period under review. For the analysis, the functions F, F_1, F_2 and their gradients were calculated for both the water and oil phases. Maps showing the streamlines and equipotential lines of fluids, the distribution of fluids along the directions of flow potential movement, and the oil-water contact boundary were developed and analyzed.

Subsequently, the coordinates and algorithms were integrated for each well to ensure precise spatial analysis and accurate modeling of fluid flow dynamics. The values for the density of oil, formation and injected water were determined through sample collection from the wells, which were subsequently analyzed in the laboratory. The results are as follows,

Density of oil, Ron = 850 kg/m³,

Density of formation water Rov = 1035 kg/m³,

Density of injected water ≈ Rozv = 1007 kg/m³ (Ron, Rov and Rozv is the terms to state densities of fluids in the algorithm).

The purpose of this study is to develop selection criteria for increasing oil production and reducing water cut in wells and to fill the existing gap. It is very crucial to know the current state of the wells and process this data in a short time. Modern reservoir simulator programs require extensive data, high costs and time. These platforms are based on certain functions; such calculations can sometimes lead to misleading results. To get the right results faster, the MATLAB platform was used in this study. Based on the functions and regularities mentioned in chapter II, the algorithm for the current state of the reservoir was built on the MATLAB platform (Appendices 1).

The acquisition of information about the current state of the well and the subsequent simulation processes that lasted for about several months caused the properties of the well to change during that time and the reservoir model to give incorrect results in the analysis. By applying this algorithm, we were able to complete the simulation process that sometimes lasted for months in a few hours. Based on the algorithm, we extracted the current hydrodynamic map of the well and we will analyze it on the following pages.

Extracting hydrodynamic maps of the current state of reservoir fluids is very important for 1) selecting the most optimal version of water injection wells, 2) improving oil recovery, 3) optimizing energy consumption, and 4) preventing water fracturing.

The study focused on the analysis taking into account the 7 criteria mentioned in the second chapter. Let's analyze the hydrodynamic maps prepared using the algorithm we applied to the current data of field X.

Figure 3.1. contains a flow line map of the water injection phase. The hydrodynamic state map of the water analyzed the streamlines and their proximity to each other, the intensive and passive fluid flow zones, the distances along the streamlines between the injection and production wells, and the proximity or distance of the injection well to the oil-water contact line. Here, the short distance between the nearly streamlines indicates a more intense flow of fluid in those places, while the large distance between the lines indicates little or no flow there. The depth for each well is taken from the depth of the productive layer and is calculated as a value per 1 meter of the corresponding filter length. The second point that we need to consider here is the scale shown on the side. The color scale on the edge of the map shows the daily flow rates (m^3/day) of fluid changing from minimum to maximum in the grid cells, and the color scale reveals stagnant and active zones.Here, a color is given for each value, and we can easily see the zones where the fluid is intensive or, conversely, less. In picture Figure 3.1., the minimum value of the scale is 22 m^3/day and the maximum value is 38 m^3/day. The color scale on the edge of the map shows the daily flow rates (m^3/day) of fluid changing from minimum to maximum in the grid cells, and the color scale reveals stagnant and active zones. In the upper right corner of the figure, the impact of injection wells #15 and #16 (well numbers are conditional) on each other and on the other #14 production wells is assessed.

Wells number #15 and #16 are the injector wells, the other 14 wells are production wells.

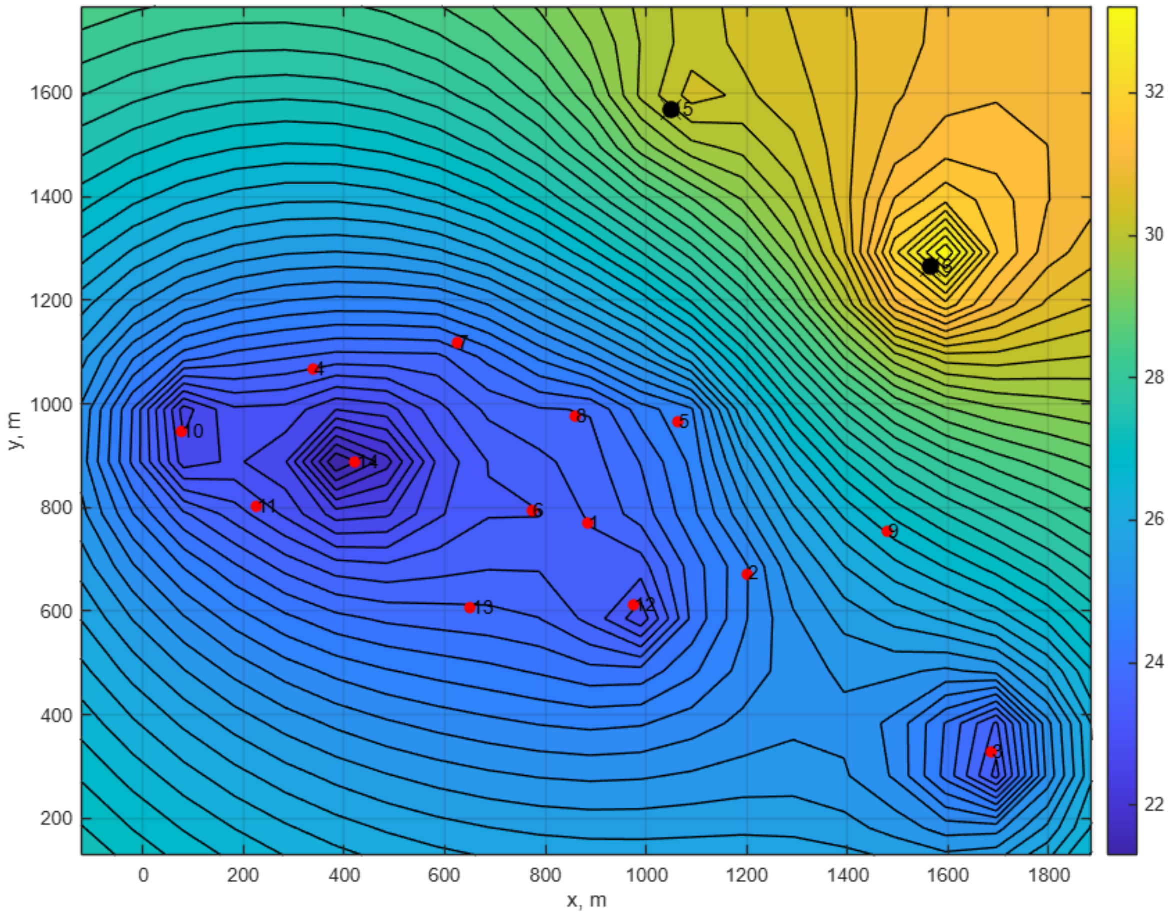

Figure 3.1. Streamlines of waterflooding processes.

The map provided for water injections shows that oil recovery is currently not going well and the water injection process in the wells is not effective. For example, the fluid (water) injected from well #16 has spread to the surrounding areas and the impact on the production wells is very low. The production wells with minimal injection process impact are wells #14, #3, #10, and #12. Equipotential lines are curves along which the potential function (Φ) remains constant. Figure 3.2. shows a map of the well along the equipotential lines, i.e. the equipotential lines determined by the difference between the flow lines. Here, the zones shown in light yellow indicate zones where water is active. The denser parts of the equipotential lines (visible as black lines in the figure) are understood as the collision of water flows and their cancellation. In Figure 3.2., the density of the lines starting from well #16 on the upper right is an indication of this and the high permeability in that zone. A broad explanation is given below. The gradient of the F_1 function, i.e. the flow direction of the injected fluid into the formation under the current operating conditions of the field, shows that the fluid injected from well number #16 impedes the movement of the fluid injected from well number #15, as a result, several production wells are expected to be flooded.

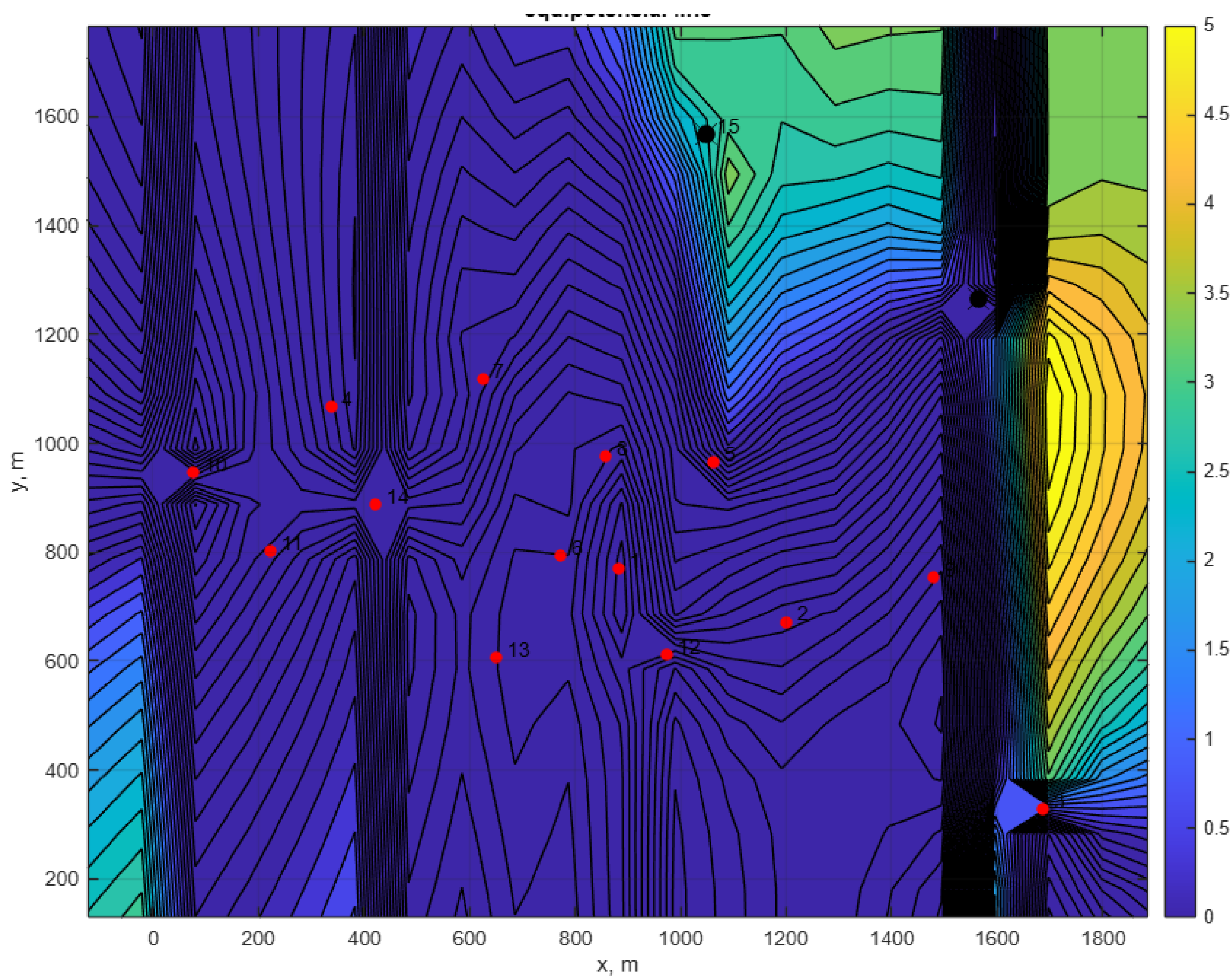

Figure 3.2. Equipotential lines of waterflooding.

Figure 3.3. shows the gradient F1, i.e. the direction of the flow lines of the injecting phase fluid in the current operating state of the field. As we have already mentioned in Figure 3.1. the fluid injected from well #16 flows in different directions. The point here is that the length of the flow axes indicates how large the flow is. Well #16 has a greater impact than well #15 and injects more fluid. It can be seen from here that well #16 has an impact on well #15, but for a more detailed analysis, let's look at the next map. With the choice of injection technology criterion in mind, effective injection of well #16 and well #15 should be carried out.

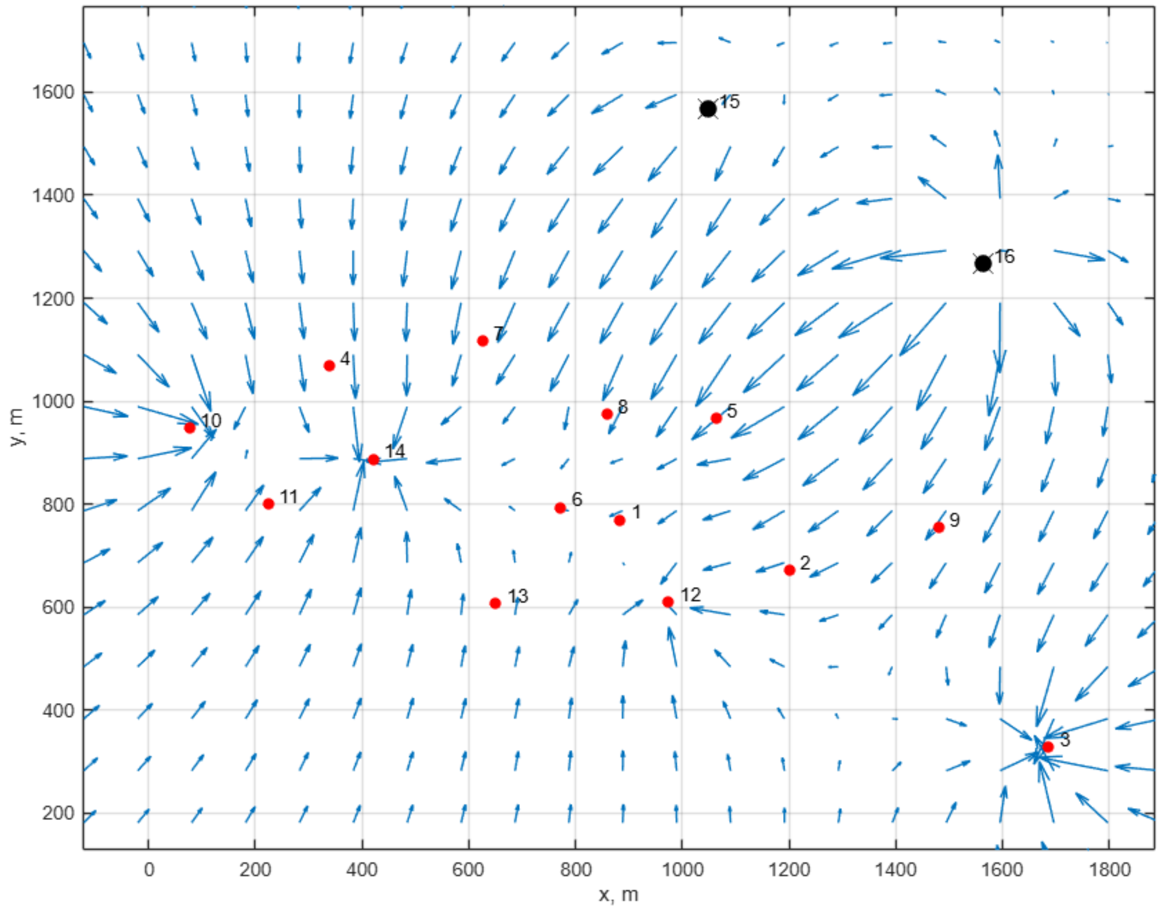

Figure 3.3. Gradients of F1(x,y) (water phase).

Figure 3.4. shows the direction in which fluids (here the water phase) have the potential to flow in the case of the field's injection wells being shut down. The point to be considered here is the same as in Figure 3.3. The directions shown in this map are a direct result of the geological situation and the permeability of the reservoir. Figure 3.3. and Figure 3.4. are mainly due to the interaction of the injection wells with each other, and as a result of this interaction, fluids collide and flow outside our area of interest. For example, in wells #15 and #16, well #16, as a result of the influence of well #15 on the flow direction, the direction of the injected fluid is inclined to the left and upwards in the figure, not towards wells #8,#5, #7 and #2. That is, it bypasses the wells. The good permeability around well #16 has an effect on the flow directions and continuing to operate in this situation may cause flooding of nearby wells (#9, #3 and #5) and loss of wells. Therefore, the well location criterion must be taken into account and the well locations must be

chosen correctly. Also, the production rate and reservoir condition criteria will help increase the effectiveness of wells, for example, preventing future flooding of well #5.

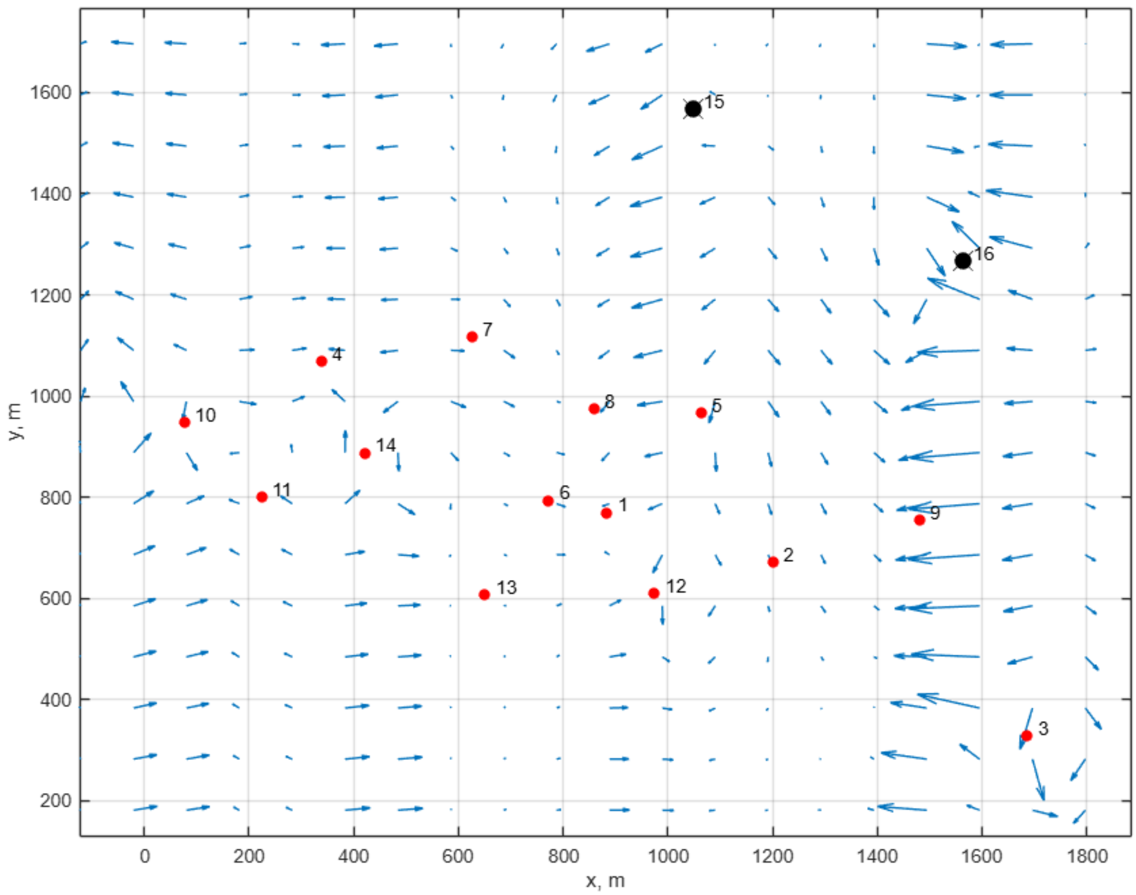

Figure 3.4. Gradients of F2(x,y) (water phase).

This map (Figure 3.5.), obtained by applying the complex potential (equation (5) $F=F_1+i\cdot F_2$), shows how fluids (water) are distributed in the reservoir. Wells #15 and #16 contain more fluids around them because they are injection wells. We observe the distribution of the zones outside the wells (lower left and upper left of the image) on the scale, which shows the movement of produced water in the reservoir. In picture Figure 3.5., the minimum value of the scale is 0 m3/day and the maximum value is 38 m3/day. In zones close to production wells, it is better for the F_2 potential to be greater than F_1 because a larger lateral distribution means better compression of oil into the wells.

Algorithm calculated the gradient and found values as, $F_1 = 0.294$ and $F_2 = 0.650$. In order to obtain effective results, F_2 must be greater than or equal to F_1. The equipotential lines are perpendicular to the streamlines.

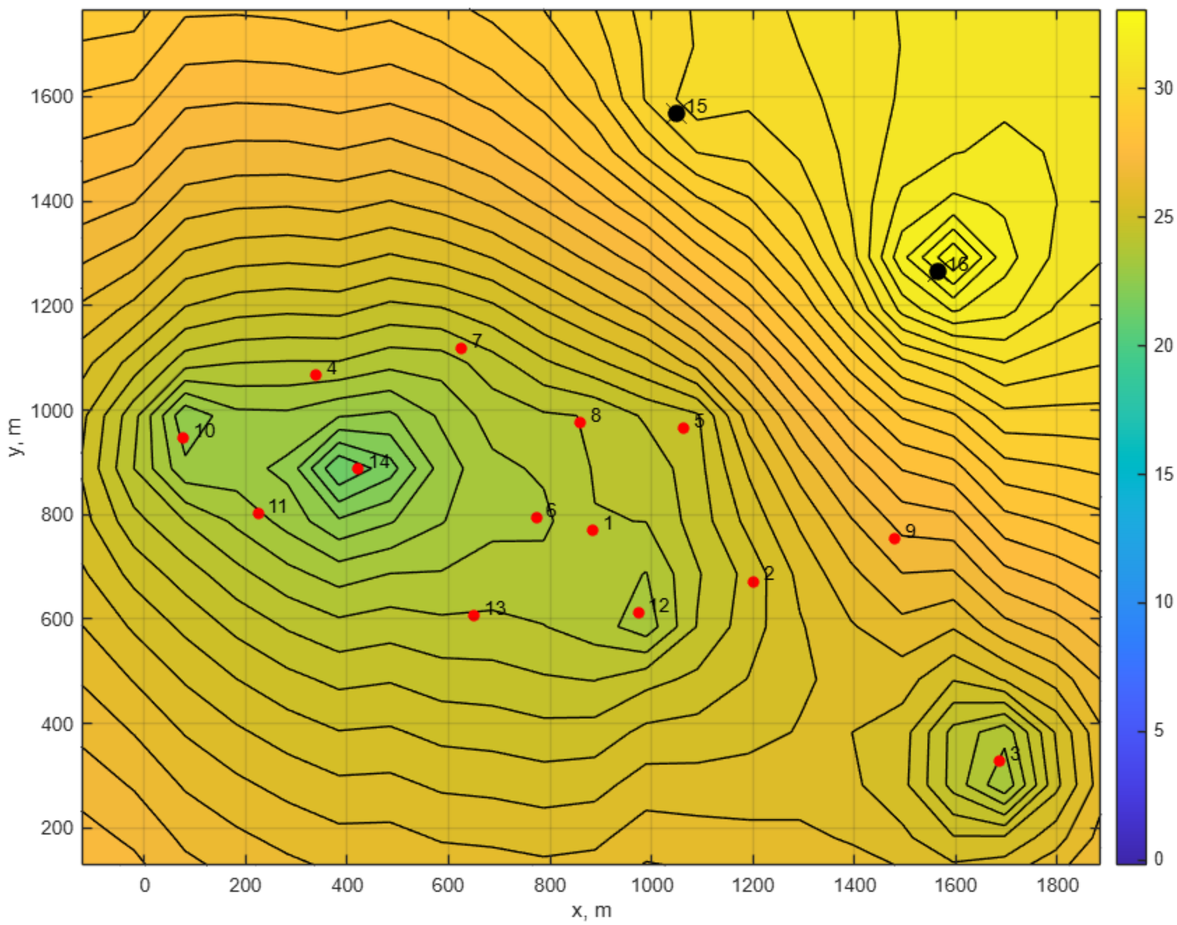

Figure 3.5. Water distribution map.

This Figure 3.5 is for comparison with streamlines and equipotential lines and shows both on the same map. If we look carefully here, there is no zone with a value of 0-5 m3/day. This shows the presence of equipotential, the equipotential was in the range of 0-5 m3/day (Figure 3.2). This is another indication of the uneven distribution, which ultimately has little impact on the production wells and shows that well #16 is injecting the water in other directions, not to push the oil into the production wells (towards the upper right corner in the figure).

Figure 3.6. shows the front of the water phase with oil and as can be seen in the figure, there is a possibility of flooding well #5. As mentioned earlier, the liquids of the water injection wells collide with each other and cancel out their effects, confirming the movement of produced water towards the wells. Another point is that there is an intrusion of produced water from outside (bottom left corner of the picture) and this supports the nearby wells. Well #3 is flooded and well #5 may also be flooded. To recover these two wells, fluid injection in well #16 must be stopped.

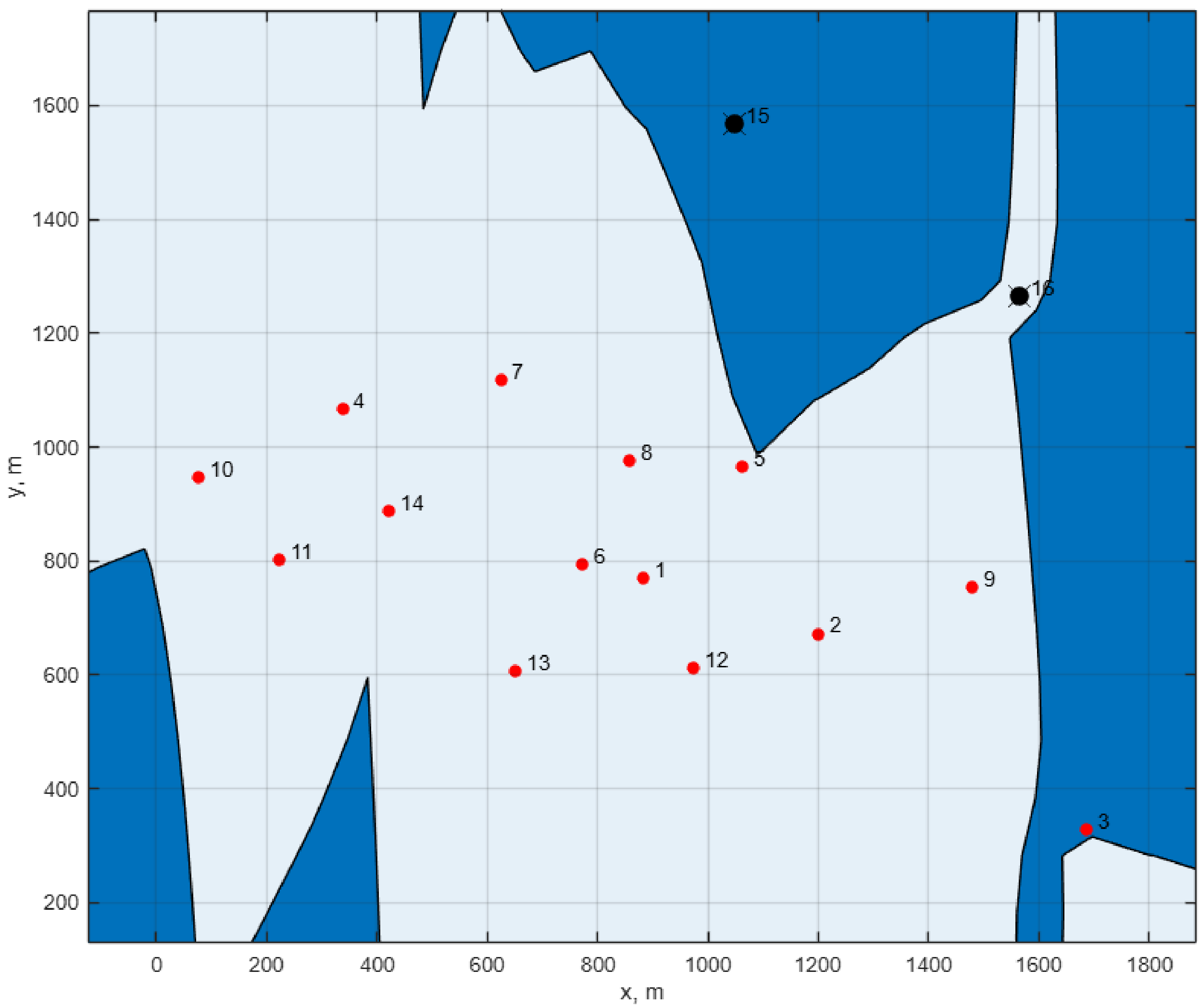

Figure 3.6. Water- oil front of the reservoir.

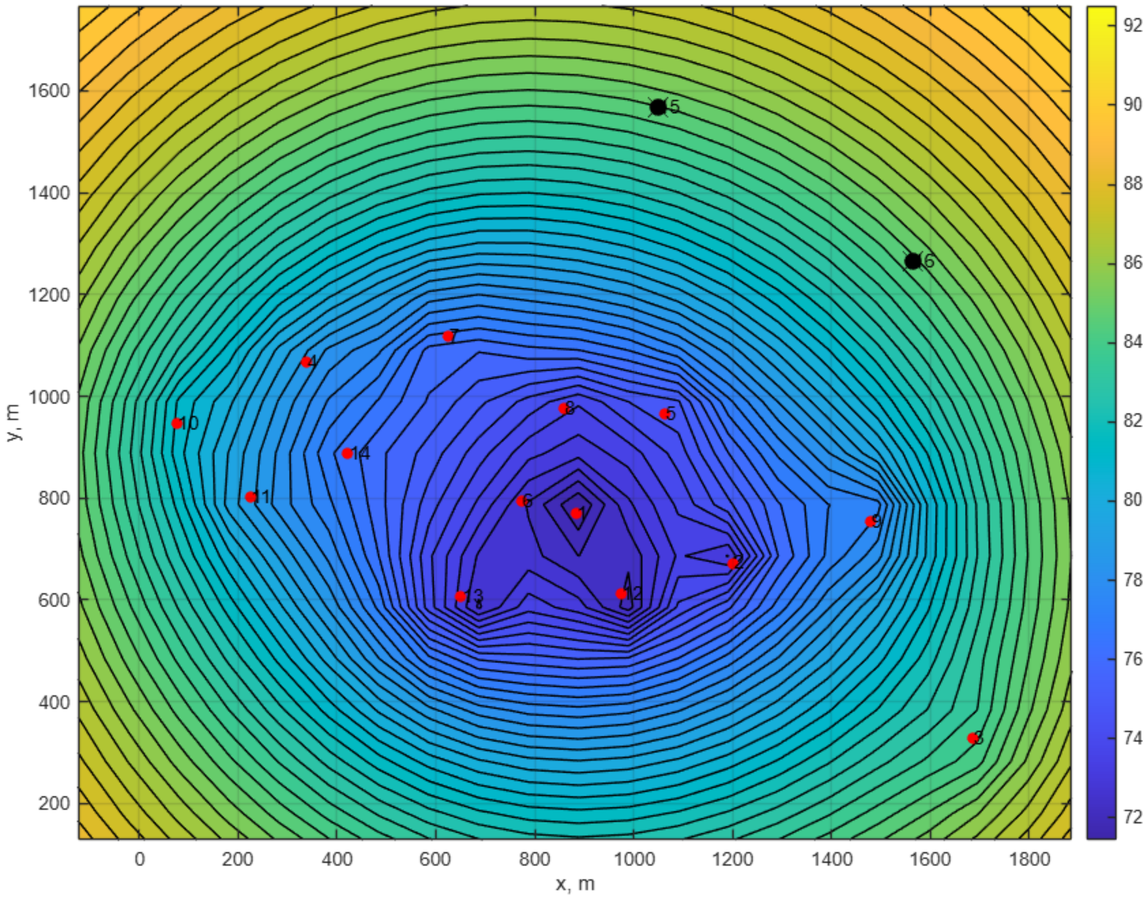

Figure 3.7. Streamlines of oil movemenet processes.

Figure 3.7. shows the oil flow lines and the water points are the same for the oil. It should be noted that the edges of Figure 3.7. are colored yellow not because there is a lot of oil flow, but because there is no data from those locations. Wells #4, #10, #11, #3 and #9 are the wells with the maximum oil flow. In picture Figure 3.7., the minimum value of the scale is 72 m3/day, and the maximum value is 92 m3/day.

If we consider the equipotential lines for oil on Figure 3.8., we can say that the collision of flow lines around wells #13, 12, #7 and #2 is more intense. In picture Figure 3.8., the minimum value of the scale is 0 m3/day, and the maximum value is 10 m3/day.

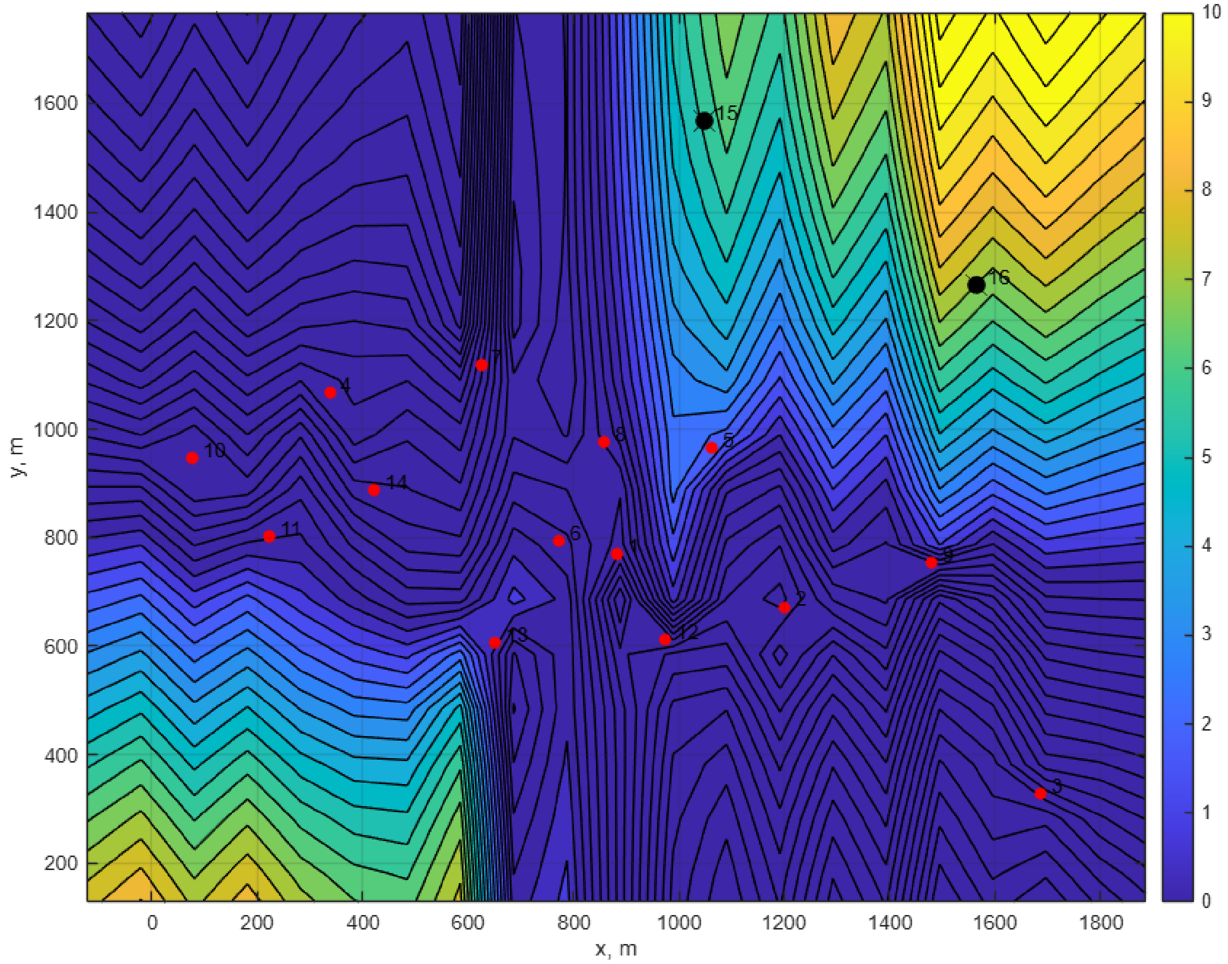

Figure 3.8. Equipotential lines of oil.

The water flowing from the outside has a good effect on wells #10 and #11, which sweep the oil towards those wells. The fluid injected from wells #15 and #16 has a greater effect on the production wells, wells #9 and #5. However, well #5 is very close to water breakthrough. On the other hand, it demonstrates once again that the injected waters intersect with each other and flow in the opposite direction to the production wells (to the left corner in the picture).

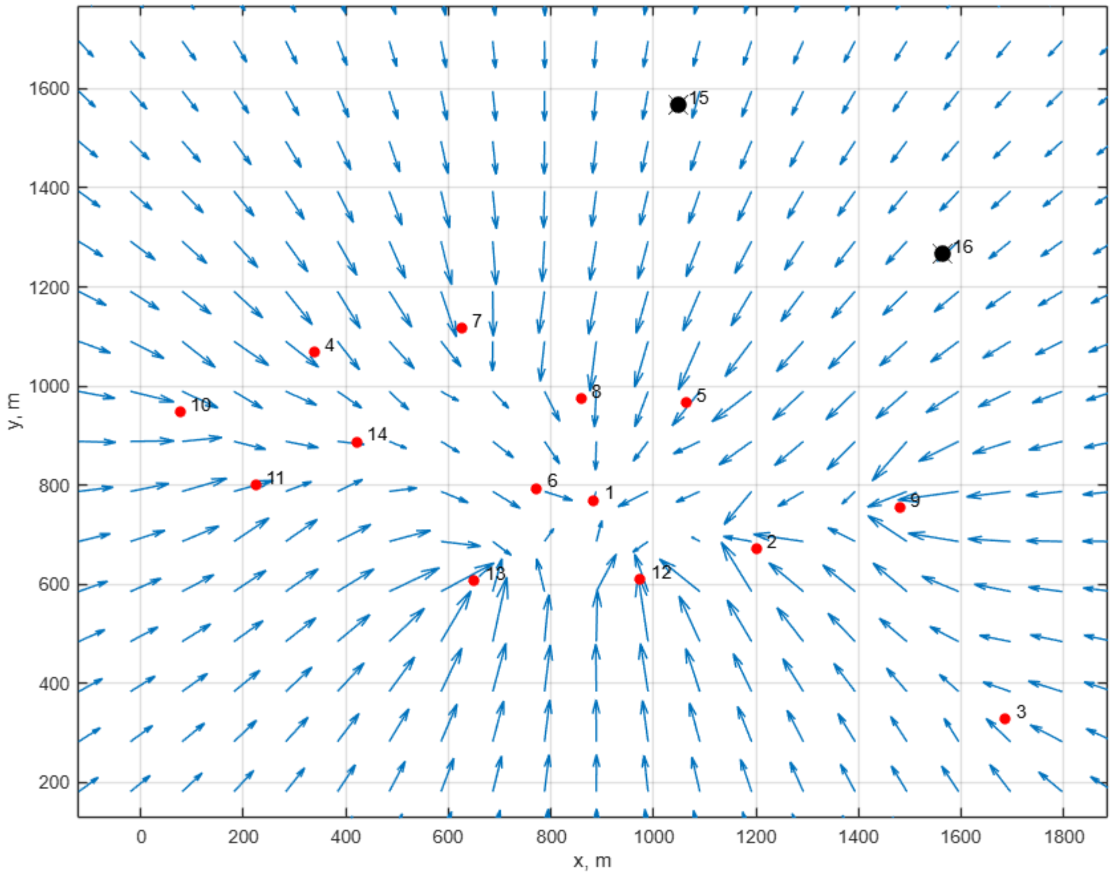

Figure 3.9. Gradients of F1(x,y) (oil phase).

The map in Figure 3.9 shows the gradient of oil flow during well operation. While there is a lot of flow around well #13, it bypasses this well, which is related to the permeability of the zone around this well. This is also true for well #9. It is observed that oil flow is low around wells #1, #14, and #6.

Figure 3.10 shows the directions in which oil has the potential to flow, and based on this, it can be said that there is a zone of high permeability between 800-1000 m on the x-axis, which prevents oil from flowing to these wells. The oil flow tends to flow sideways from well #5. It appears that the oil around well #15 tends to flow away from the production wells and there is a need to inject fluids from well #15 to sweep the oil towards the production wells.

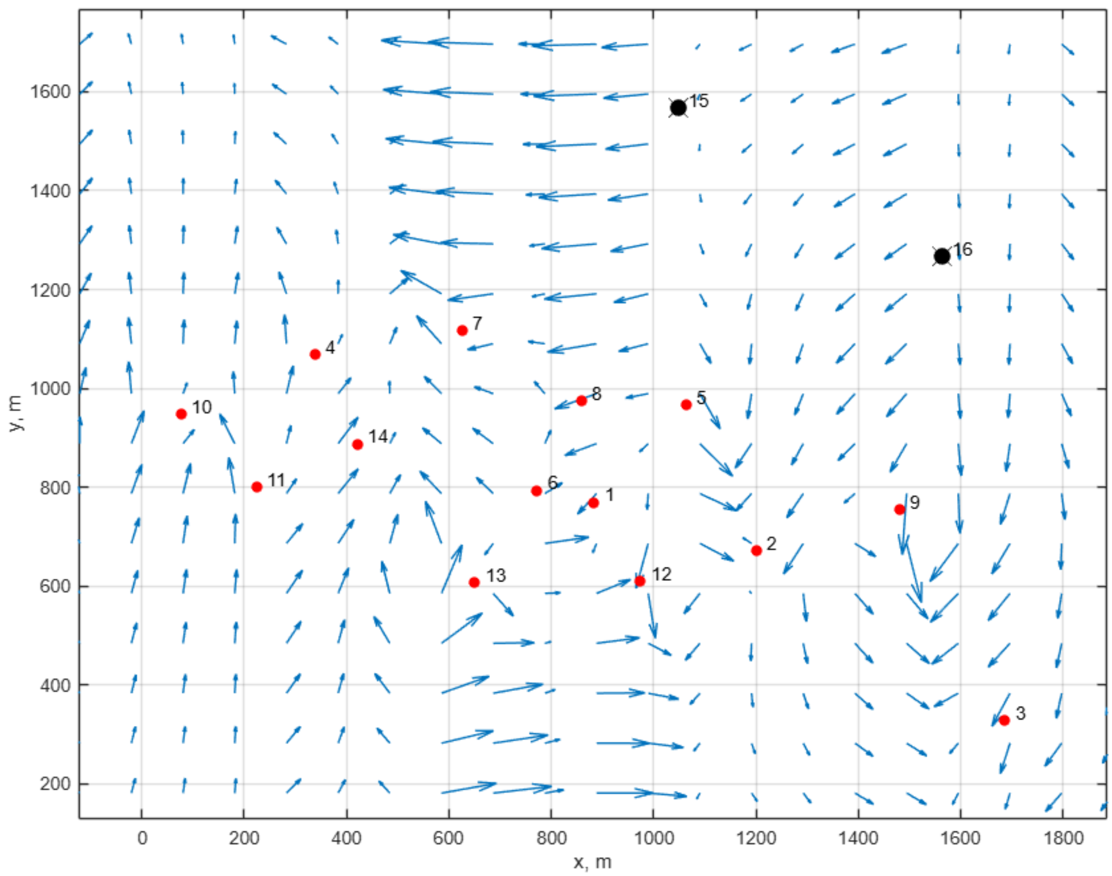

Figure 3.10. Gradients of F2(x,y) (oil phase).

RESULTS

1. In this study, a diagnostic assessment of the current state of the reservoir was carried out based on both theoretical and practical grounds, with special attention to the zonal impact mechanisms of the reservoir. This approach allowed us to generalize the injection methods applied through injection wells in order to increase oil production. The application of injection well selection criteria is of great importance for optimizing oil production and managing subsurface fluids. In this study, attention was paid to the injection well selection criteria.

2. Taking into account the interference between wells and conducting a diagnostic assessment of the reservoir system, the selection criteria for injection wells have been developed on a scientific basis. The application of these criteria allows solving many important issues encountered in the oil industry, including;
    - The current state of the stagnant and active filtration zones is determined, which allows the selection of injection wells and the directions of movement of reservoir fluids and the working agent injected into the formation to be taken into account based on this information.
    - Based on the determination of the zonal and spatial boundaries of the water-oil contact line, the selection of injection wells is carried out.
    - Based on the application of these criteria, the operation of the selected injection well can be monitored before and after the injection process, based on the appropriate analysis of the injection well in the selected area. This process becomes a mechanism that increases the efficiency of oil production and quickly detects potential problems.
3. The software module developed in the interactive environment of the MATLAB program is used to select the injection well. This program, using less data, significantly speeds up the stages of analysis of analytical results. The process of collecting data and analyzing analytical results takes about 1-3 days, and the calculation procedure itself takes about 20 minutes. This allows for optimization of the selection of injection wells and more efficient, accurate and timely decisions.

The use of the methodology applied in this study was demonstrated on the example of field X. A detailed analysis of the real situation for field X was carried out and the current state of the field was determined as follows. Hydrodynamic models were prepared and analyzed one by one using the criteria developed.

As a result, it is proposed that the injection of fluids from well #16 be stopped. It is expected that water injections will give more effective results by minimizing formation damage, and our second proposal for this well is to increase the water injection rate. For 30 days, well #3 supplied 3578 tons of water and 934 tons of oil. This well is already flooded with water with 79% water cut and it produces injection fluid. Therefore, the well is recommended to shut down and conversion to injection well. Injection wells should be selected based on matching the optimal flow rate for the reservoir.

With the application of these criteria, there is no need to apply tracer technology. Tracer technology is expensive, as operations on about 3 wells can cost about 200,000 manats *(Ibragimov, Huseinova, & Gadzhiev, 2021).* Moreover, the observation process associated with this technology can last up to several months, which significantly increases the time requirements. The use of tracer technology also requires continuous monitoring, regular testing and subsequent analysis, all of which increases the overall workload and operating costs *(Tayyib, Al-Qasim, Kokal, & Huseby, 2019).*

The implementation of the proposed criteria allowed us to avoid the use of tracer technology, which provided significant advantages. By not utilizing tracer methods, we were able to save both time and costs, as high operational expenses associated with tracers were eliminated.

CONCLUSION

This study, based on both theoretical frameworks and practical applications, conducted a detailed diagnostic assessment of the reservoir, with particular attention to the zonal impact mechanisms within the reservoir. This approach not only allowed for the generalization of various injection methods but also led to the development of precise injection well selection criteria, which are essential for optimizing oil production and fluid management in the reservoir. Careful analysis of these criteria is essential to ensure that the right wells are selected based on their characteristics and potential to contribute to oil production. The study further developed these selection criteria by focusing on addressing well impact issues and assessing the overall condition of the reservoir system. By conducting a comprehensive diagnostic assessment, it was possible to identify injection wells that would optimize production and optimize the recovery process. The analysis showed that the current state of the stagnant and active filtration zones plays a key role in determining the optimal well placement and fluid flow directions. One of the main results of this study is that it allows for early detection of any operational problems by monitoring the performance of selected water injection wells before and after the injection process. The application of these criteria provides a mechanism for improving oil recovery and allows for more effective management of reservoir fluid dynamics.

The software module developed in the MATLAB environment has also greatly simplified the well selection process. The system can complete data collection and analysis by using less data and providing faster analysis. This allows for timely and complete well selection decisions, which ensures optimal placement of the injection well.

Using the criteria developed in this study, a detailed analysis was conducted for field X, where hydrodynamic models were built and analyzed, and an extensive analysis was performed.

The results of this study offer promising applications for the oil industry moving forward. By optimizing the well selection process, it allows for effective reservoir diagnostics and accurate results in a short time. Eliminating tracer technology from the well selection process significantly reduces both costs and time spent on well evaluation, achieving higher operational efficiency. This approach not only simplifies operations but also allows for faster implementation of improved recovery methods.

Looking ahead, the implementation of the proposed well selection criteria could have a significant impact on reservoir management in various oil fields. These findings contribute to better field analysis by helping operators make informed decisions based on both technical and economic factors.

In terms of future research, the methodology developed in this work can be expanded to include additional criteria such as more advanced machine learning algorithms. The continued integration of real-time data and advanced simulation tools will further enhance the accuracy and applicability of these well selection criteria across diverse geological conditions. In addition, automation and artificial intelligence (AI) can be integrated into the decision-making process to provide more efficient, real-time analysis.

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Input form for the initial data required for the calculation and visualization of filtration velocity distribution on the selected area of the field (using the data from the "X" field) with explanations for the user:

Step 1. Specify the time period for which the initial data is taken:

Date: Development period starting from September 2023.

Step 2. Input data by well numbers regarding the performance of production and injection wells during the considered period in tabular form:

Calculation Section of the Program "Streamlines and Equipotentials"

Nskv = matrix1(:,1) % Well numbers in numerical format.

QN = matrix1(:,2) % Mass flow rate of oil from producing wells, measured in tons.

QV = matrix1(:,3) % Volumetric flow rate of water from producing wells, measured in m^3.

QVt = matrix1(:,4) % Mass flow rate of water from producing wells, measured in tons.

% If the volume of produced water is measured in m^3, then: QV = QV. If measured in tons, then with water density (Rov), QV = (((QV * 1000) / Rov)).

QG = matrix1(:,5) % Gas production, measured in m^3.

xx = matrix1(:,6) % Digitized coordinates (along the x-axis) of the well on the development map (in mm).

yy = matrix1(:,7) % Digitized coordinates (along the y-axis) of the well on the development map (in mm).

Filtr = matrix1(:,8) % If the calculation is performed considering how the produced production is distributed along the filter length, specify the filter height.

Kd1 = matrix1(:,9) % Number of days the wells have operated during the study period.

matrix1 (n, m) is the name of the matrix where:

- The 1st column contains the well numbers,
- The 2nd column contains the corresponding oil flow rates (in tons),
- The 3rd and 4th columns contain the water flow rates (in m^3 and tons),
- The 5th column contains the gas flow rate (in m^3),

- The 6th and 7th columns contain the digitized coordinates of the well on the development map (in mm),
- The 7th column contains the length of the well filter,
- The 8th column contains the number of operating days for the wells during the considered period

Step 3. matrix2 (n, m) is used to input information about the injection wells (planned for conversion to injection wells) skv1, their numbers (1st column), and the digitized coordinates XX1, YY1 (5th and 6th columns) in mm. If the calculation considers how the production is distributed per unit height of the filter, then the filter height Filtrn (7th column) must be provided. The filter height should be set to 1 if such consideration is not planned. The actual (planned injection volume) should be indicated with a minus sign (2nd and 3rd columns) QQZ, along with the well's operating days KD1 (8th column). If gas injection is being conducted or planned, this information should also be entered (4th column).

Code for scale and density of fluids:

% Enter the map scale (1mm: meters)

h = 1;

% To calculate the monofractal dimension of the water propagation line,

% the grid cell size should be chosen for the area subdivision.

% For this, specify the number of division points and the range of changes in coordinates along the X and Y axes (ry).

ry = 20;

% Enter the density of oil in kg/m³

Ron = 850;

% Enter the density of formation water (Rov) and injected water (Rozv) in kg/m³

% Fresh water density Rov = 1000 kg/m³, formation water density ≈ Rov = 1025-1030 kg/m³,

% seawater density Ro (seawater) = 1025 kg/m³

Rov = 1035;

Rozv = 1007;

Code for daily production of fluids:

Calculation of Oil Production Volume Per Day:

```
% Calculate the daily oil production volume
qn = (((QN * 1000) ./ Ron) ./ Filtr) ./ Kd1;
```

Calculation of Water Production Volume Per Day:

```
% Calculate the daily water production volume
qv = (QV ./ Filtr + ((QVt * 1000) ./ Rov) ./ Filtr) ./ Kd1;  % Volume of produced water
```

Calculation of Gas Production Volume Per Day:

```
% Calculate the daily gas production volume
qg = (QG ./ Filtr) ./ Kd1;  % Volume of gas produced per 1m of filter, m³
```

Code for studied fluids:

```
% Define the studied agent - oil (qn), water (qv), oil + water (qj), gas (qg)
q = qv;
```

in the research both water and oil were studied separately and compared the results.

Abbreviation / Symbol	**Full Term / Meaning**
EOR	Enhanced Oil Recovery
Streamlines	Streamlines are curves that are tangent to the velocity vector at every point in the flow field and represent the actual path of fluid motion in a steady flow.
Equipotential lines	Equipotential lines are curves along which the potential function (Φ) remains constant. If the given velocity potential satisfies the Laplace equation, then the fluid flow is a representation of the steady incompressible irrotational flow.
Stream function	The stream function Ψ(x,y) is a mathematical tool used to describe the flow of an incompressible fluid in a two-dimensional (plane) flow field. Known as Lagrange stream function, which introduced by Joseph Louis Lagrange. It helps visualize and analyze the movement of fluid through a porous medium by defining streamlines.
Filtration	Filtration means here the process of a fluid movement through a porous medium. This movement is powered by Darcy's Law, which describes how the flow rate depends on the permeability of the material, the viscosity of the fluid, and the pressure gradient.
TTP	Time of flight to producer
Velocity potential	Velocity potential (ϕ) or potential function is a scalar potential used in potential flow theory. Unlike a stream function, a velocity potential can exist in three-dimensional flow.
TOF	Time of flight
PI	Productivity index
WOC	Water-oil contact

Abbreviation / Symbol	**Full Term / Meaning**
NPV	Net present value
HF	Hydraulic fracturing
FL	Fuzzy logic
ANN	Artificial neural networks
AI	Artificial intelligence
SAGD	Steam-assisted gravity drainage
CP	Contact parameter