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Updated screening criteria for steam flooding based on oil field projects data

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UPDATED SCREENING CRITERIA FOR STEAM FLOODING BASED ON OIL FIELD PROJECTS DATA

by

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ABSTRACT

Enhanced oil recovery (EOR) screening is considered the first step in evaluating potential EOR techniques for candidate reservoirs. Therefore, as new technologies are developed, it is important to update the screening criteria. Many of the screening criteria for steam flooding that have been described in the literature were based on data collected from EOR surveys biennially published in the *Oil & Gas Journal*. However, these datasets contain some problems, including outliers, missing data, inconsistent data and duplicate data, that could affect the accuracy of the results. Despite the importance of ensuring the quality of a dataset before running analyses, data quality has not been addressed in previous research related to EOR screening criteria. The objective of this current work was to update the screening criteria for steam flooding by using a database that had been cleaned. The original dataset included 1,785 steam flooding field projects from around the world (Brazil, Canada, China, Colombia, Congo, France, Germany, Indonesia, Trinidad, U.S. and Venezuela). These projects had been reported in the *Oil and Gas Journal* from 1980 to 2012. After detecting and deleting the duplicate projects, only 626 field projects remained. To analyze and describe the results of the dataset, both graphical and statistical methods were used. A box plot and cross plots were used to detect and identify data problems, allowing for the removal of outliers and inconsistent data. Histogram distributions and box plots were used to show the distribution of each parameter and present the range of the dataset. New screening criteria were developed based on these statistics and the defined data parameters. The developed criteria were compared with previously published criteria, and their differences are explained.

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I am immensely grateful to my advisor, Dr. Baojun Bai. who not only served me as my supervisor but also encouraged and challenged me throughout my accademic program. Without his constant support, encouragement and guidance, this work would not have been possible. I thank him for accepting me as one of his graduate students, being so patient and pushing me to be a better engineer.

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NOMENCLATURE

Symbol	Description
s	Saturation, fraction
ρ	Density of the fluid
ø	Porosity, percent
h	Formation thickness, ft
P_p	Pore pressure, psi
T	Temperature, ^oF
p	Reservoir pressure
μ_o	Oil viscosity, (cp)
μ_w	Water viscosity, (cp)
k_w	Water relative permeability, fraction
k_o	Oil relative permeability, fraction
D	Reservoir depth
md	Millidarcy
cp	Centipoise
ft	Foot
F	Fahrenheit
M	Mobility ratio, dimensionless
N	Original oil in place, STB
EOR	Enhanced Oil Recovery
IOR	Improved Oil Recovery
OOIP	Original oil in place
SOR	Steam oil ratio
E_D	Displacement efficiency
E_S	Sweep efficiency

1. INTRODUCTION

Steam flooding is a conventional thermal EOR method that has been applied in many heavy oil reservoirs around the world. This technique also is referred to as continuous steam injection and steam drive. In this process, steam is injected continuously through an injection well or wells, while oil is produced through a different well or wells (Iyoho, 1978). Steam helps to make the conditions favorable for pushing the oil toward the producing well by reducing its viscosity, which improves its mobility ratio (M) and, therefore, its displacement and areal sweep efficiency (Hong, 1994). In steam flooding, the injected steam not only lowers the oil viscosity, but also supplies the drive energy. As the steam loses heat to the formation, it condenses into hot water, which, coupled with the continuous supply of steam behind it, provides the drive to move the oil to production wells (Farouq Ali, 1974). Steam flooding has been applied as the stages of primary, secondary and tertiary recovery process. Recovery efficiency by steam flooding can reach 50-70% of OOIP (Hong, 1994).

Numerous enhanced recovery techniques exist today. These techniques and their applications and results have been translated into screening criteria (Iyoho 1978). Applying these screening criteria (or screening guides) is one of the first steps in determining whether the field in question can be produced by a certain recovery method (Chu, 1985). Prospects that pass this screen are candidates for further engineering study. The criteria include values for parameters such as oil gravity, oil viscosity, reservoir porosity, oil saturation start and end, reservoir permeability, reservoir depth, reservoir temperature, reservoir pressure and pay thickness. The criteria recommend minimum to maximum ranges for each parameter.

This is research reviewed recent development in steam flooding enhanced oil recovery (EOR) techniques. It is also updated steam flooding screening criteria developed by several authors from 1973 to 2010. The new criteria were based on field applications data reported in Oil and Gas Journal (1980 – 2012). After cleaning the data, a new set of screening criteria has been made for steam flooding. The updated screening criteria are shown by tables and graphs.

1.1. OBJECTIVE OF THE STUDY

The objective of this study is to update screening criteria for steam flooding and show the data distribution of each parameter that affects stream flooding selection. In this work, the field projects data reported in EOR surveys in *Oil & Gas Journal* were used to develop the criteria. To achieve this objective, it is essential to ensure that the data is of high quality and produces reliable results. Therefore, data cleaning methods were applied to identify and remove duplicate, inconsistent and missing data. After cleaning the dataset, both graphical and statistical methods were used to display and summarize the data in order to develop the new screening criteria.

1.2. THESIS OUTLINE

This thesis is organized into six sections. Section 1 is the introduction and the objective of the study. Section 2 is a literature review and basic theories for oil recovery mechanisms, enhanced oil recovery methods, thermal processes and enhanced oil recovery screening criteria. This section also provides a summary of screening criteria for steam flooding. Steam flooding mechanisms, application conditions and design projects explained in detail in Section 3. Section 4 gives an explanation of the data collection and cleaning processes for steam flooding projects. Section 5 is the data analysis for the cleaned dataset. Finally, data summary and conclusions of this research are given in Section 6.

2. LITERATURE REVIEW

This section describes a literature review of oil recovery mechanisms, enhanced oil recovery, thermal processes and EOR screening criteria. Also screening criteria for steam flooding have been reviewed.

2.1. OIL RECOVERY METHODS

Oil recovery methods can be divided into three major categories: primary, secondary and tertiary recovery (enhanced oil recovery), as show in figure 2.1. In the primary process, the oil is forced out of the petroleum reservoir by existing natural pressure of the trapped fluids in the reservoir. Primary oil recovery methods include solution-gas drive, gas-cap expansion, gravity drainage, rock expansion, water drive processes or their combination. With declining reservoir pressure, it becomes more difficult to get the hydrocarbons to the surface. Sometimes, artificial lift is required. On average, only 5-10% of original oil in place can be recovered by primary techniques.

Over a period of oil production, the reservoir energy will fall, and at some point, there will be insufficient underground pressure to force the oil to the surface. When a large part of the crude oil in a reservoir cannot be recovered by primary methods, a method for recovering more of the oil left behind must be chosen. Most often, secondary recovery is accomplished by injecting gas or water into the reservoir to replace produced fluids and maintain or increase the reservoir pressure. Conversion of some production wells to injection wells and subsequent injection of gas or water for pressure maintenance in the reservoir has been designated as secondary oil recovery. The oil recovered by both primary and secondary processes ranges from 20 to 50% depending on the oil and reservoir properties (Speight, J. G. 2009).

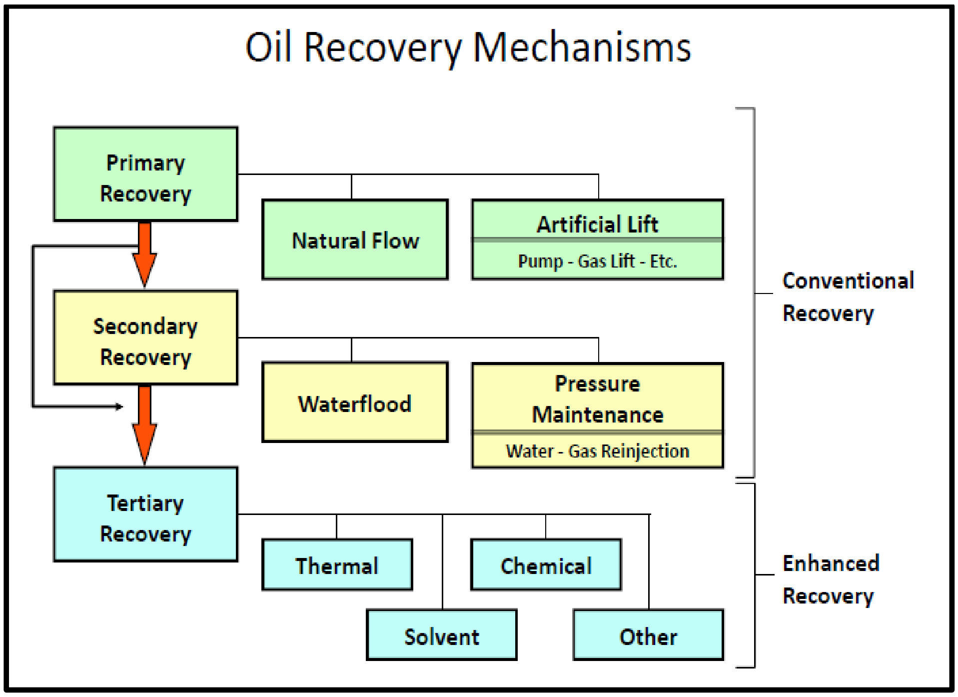

Figure 2.1. Oil recovery methods (Oil and Gas Journal, 1990)

The biggest portion of oil left behind after conventional oil recovery exhausted. Therefore, enhanced oil recovery methods must be applied if further oil is to be recovered. Enhanced oil recovery (Tertiary recovery) methods have focused on recovering the remaining oil from a reservoir that has been depleted of energy during the application of primary and secondary recovery methods.

Enhanced oil recovery is often synonymous to some extent with *improved oil recovery* (IOR). *Enhanced oil recovery* (EOR) is the recovery of oil from a reservoir by the injecting of materials that not normally present in reservoir (Lake, 1989). The injected fluids interact with the reservoir rock and oil system to create conditions favorable for oil recovery. *Improved oil recovery* (IOR) refers to any process or practice that improves oil recovery. IOR includes EOR processes and other practices such as water flooding, pressure maintenance, infill drilling, and horizontal wells.

2.2. ENHANCED OIL RECOVERY METHODS

In general, EOR methods can be classified into two major groups: thermal and non-thermal processes, as show in figure 2.2. Each main group has a different EOR processes. Each technique has different concepts but similar objective which is to recover remaining oil and improving the recovery rate (Green and Willhite, 1998). EOR processes are important as technologies that could help meet the growing demand for oil in the world. It is estimated that roughly 65% of the original oil in place (OOIP) remains in the reservoir after primary and secondary recoveries. This remaining oil can be recovered by applying suitable EOR processes. The potential for EOR processes is clearly substantial and is responsible for the growth of EOR projects in all oil producing regions of the world (Ezekwe, 2011).

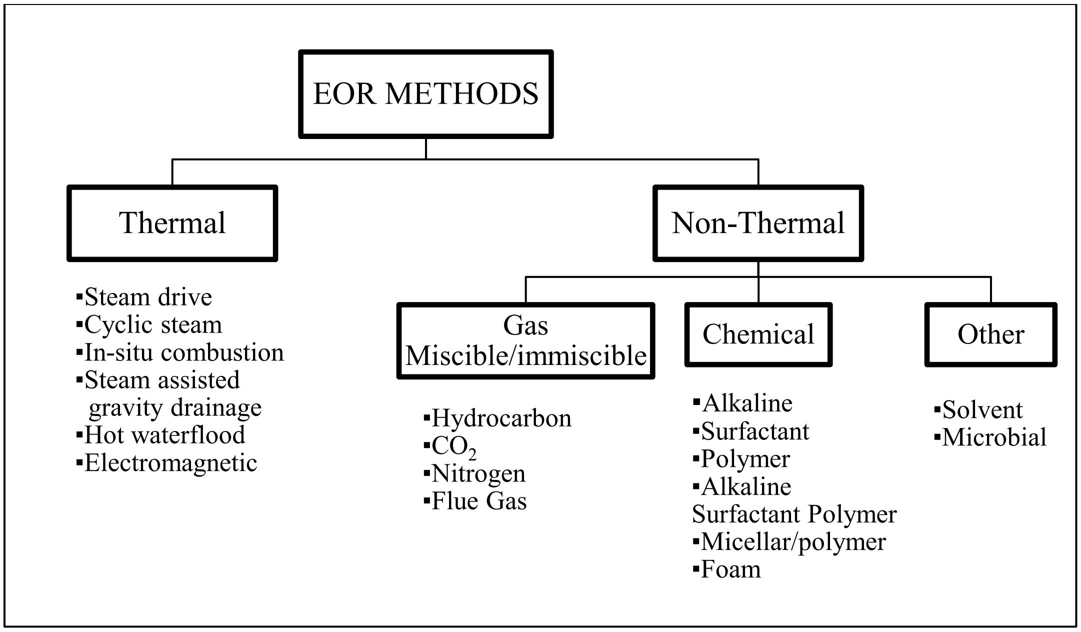

Figure 2.2. Enhanced oil recovery methods (Ali, S. M. F., & Thomas, S., 1989)

EOR refers to the recovery of oil through the injection of fluids and energy not normally present in the reservoir. The injected fluids must accomplish one of the objectives as follows:

A. Boost the natural energy in the reservoir
B. Interact with the reservoir rock/oil system to create conditions favorable for remaining oil recovery.
C. Reduction of the interfacial tension between the displacing fluid and oil.
D. Increase the capillary number.
E. Reduce capillary forces.
F. Increase the drive water viscosity.
G. Provide mobility-control.
H. Oil swelling.

I. Oil viscosity reduction.

J. Alteration of the reservoir rock wettability.

EOR processes are very sensitive to oil prices. The price of oil on a sustainable basis must exceed the cost of the injectant plus operating costs by a sizeable margin for an EOR process to be considered economical. For this reason, an EOR process must be efficient in terms of cost per barrel of oil recovered and also effective in substantially increasing the volume of oil recovered beyond the current recovery process. Economic evaluation is the key important step in the selection of an EOR process and is emphasized throughout the selection process.

An EOR process was deemed successful only if it was both an engineering and an economic success (Iyoho, 1978)**.** The goal of EOR processes are to mobilize the oil left behind after conventional methods and to increase the overall oil displacement efficiency, which is a function of microscopic and macroscopic displacement efficiency (Green & Willhite, 1998). Oil displacement efficiency is increased by decreasing oil viscosity (thermal and miscible flood) or by reducing capillary forces or interfacial tension (chemical and miscible).

Figure 2.3 illustrates a schematic of microscopic and macroscopic sweep efficiencies. Microscopic efficiency refers to the mobilization of oil at the pore scale and measures the effectiveness of the displacing fluid in moving the oil at those places the displacing fluid contacts the oil. Microscopic efficiency can be increased by reducing capillary forces or interfacial tension between the displacing fluid and oil or by decreasing the oil viscosity (Satter et al., 2008). Macroscopic or volumetric displacement efficiency refers to the effectiveness of the displacing fluid in contacting the reservoir in a volumetric sense. Volumetric displacement efficiency also known as conformance indicates the effectiveness of the displacing fluid in sweeping out the volume of a reservoir, both areal and vertically, as well as how effectively the displacing fluid moves the displaced oil toward production wells (Green & Willhite, 1998).

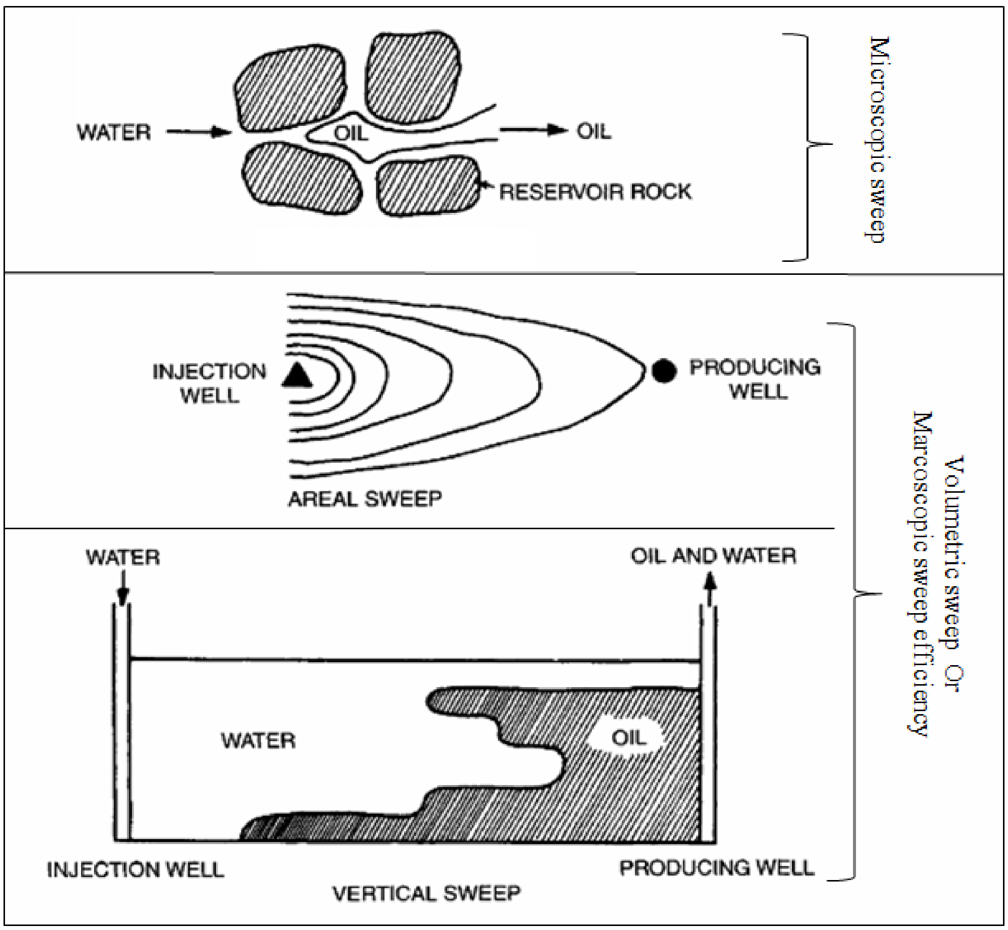

Figure 2.3. Schematics of microscopic and macroscopic sweep efficiencies (Lyons and Plisga, 2005)

The target of EOR processes varies considerably for the different types of hydrocarbons. Figure 2.4 shows the fluid saturations and the target of EOR for typical light and heavy oil reservoirs and tar sands. For light oil reservoirs, EOR is usually applicable after secondary recovery operations, and the EOR target is ~45% OOIP. Heavy oils and tar sands respond poorly to primary and secondary recovery methods, and the bulk of the production from such reservoirs come from EOR methods (Thomas S., 2007).

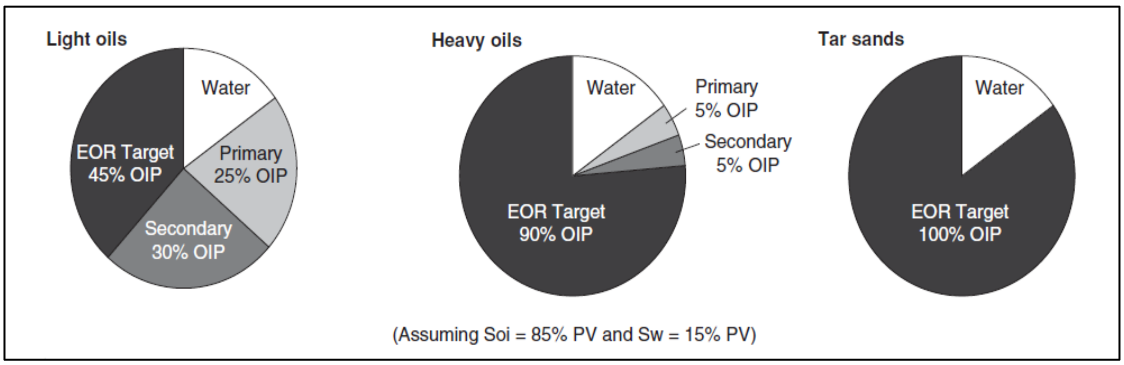

Figure 2.4. EOR target for different hydrocarbons (Thomas S. 2007)

2.3. THERMAL EOR METHODS (PROCESSES)

Thermal EOR processes are defined to include all processes that supply heat energy to the reservoir and enhancing the ability of oil to flow by reducing its viscosity. Thermal recovery processes are globally the most advanced EOR processes. The key of thermal recovery is the use of heat to lower the viscosity of oil and reduces mobility ratio, therefore, increases the productivity and recovery. The oil caused to flow by the supply of thermal energy is produced through production wells. When heated, oil becomes less viscous and flows more easily. Because this is an important property of oil, considerable effort has been devoted to the development of techniques that involve the introduction of heat into a reservoir to improve recovery of the heavier, more viscous crude oils.

The viscosity of oils dramatically decreases as temperature increases, and the purpose of all thermal oil recovery processes is therefore to heat the oil to make it flow easier. Figure 2.5 shows the sensitivity of viscosity to temperature for several grades of oil and water. The sharp decrease of crude oils viscosity with temperature, especially for the heavier crude, largely explains why thermal EOR has been so popular.

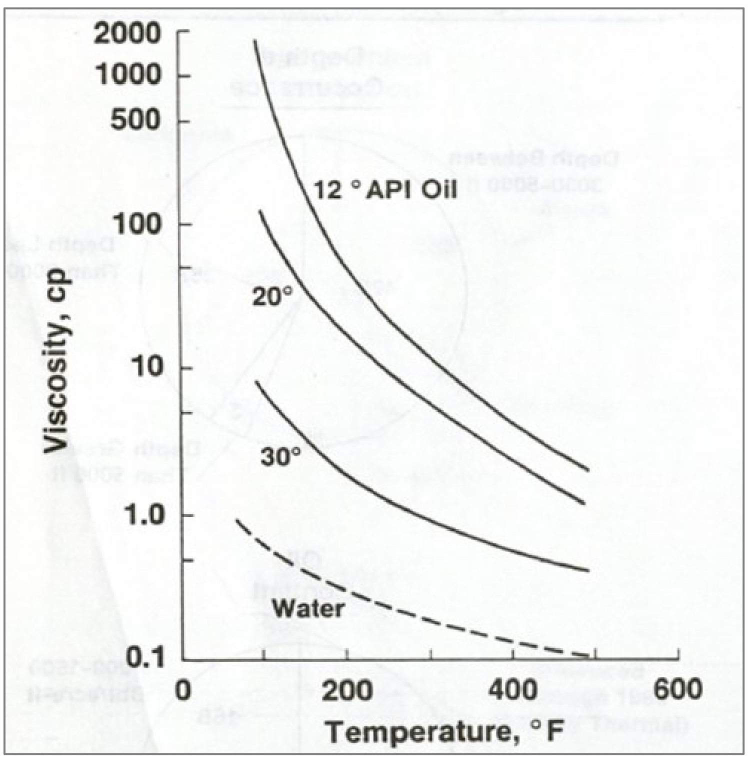

Figure 2.5. Viscosity Reduction of Oils and Water (Hong, K.C., 1994)

In general, thermal enhanced oil recovery can be subdivided into the following categories:

A. Major thermal processes in use today:

1. Steam flooding (Steam drive: SD)
2. Cyclic steam stimulation (CSC)
3. Steam assisted gravity drainage (SAGD)
4. In-situ combustion (ISC)

B. Other processes which are not as widely implemented:

1. Electrical/electromagnetic heating.
2. Hot water flooding.

2.3.1. Steam Flooding (SD). Also called steam drive. In this process, two separate wells are used, one for steam injection and the other for oil production. Steam is injected continuously at injectors with the aim of driving oil towards producers. The steam injection is continuous until the process becomes uneconomic or is replaced by another process. Figure 2.6 shows a schematic of steam flooding process.

Steam reduces the oil saturation in the steam zone to a very low value, pushing the mobile oil out of the steam zone. As the steam zone grows, more oil is moved from the steam zone to unheated zones ahead of the steam front. There the oil accumulates to form an oil bank. Then the oil is produced using artificial lift. A detailed discussion follows later in the (steam flooding) section.

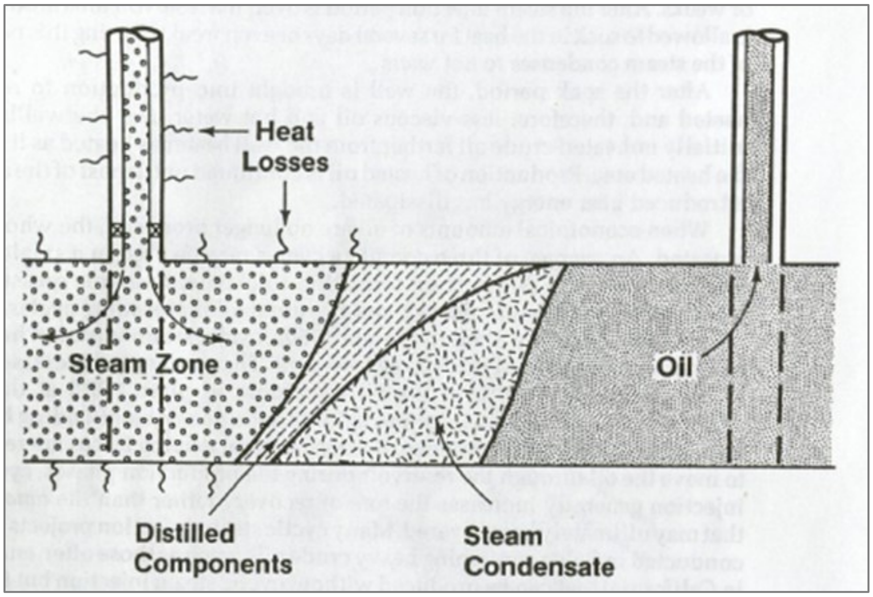

Figure 2.6. Schematic of steam flooding process(Hong, K.C., 1994)

2.3.2. Cyclic Steam Stimulation (CSS). Also called steam soak or Huff-and-Puff. In this process one well uses as both injector and producer. It involves injecting steam into a well for several days or weeks, shutting the well in as long as necessary to allow the steam to heat the oil in the areas around the well. During this period, most of the steam condenses to hot water. After the soak period, the well is back to production to recover the heated oil. Figure 2.7 shows a schematic of cyclic steam stimulation process. This process is repeated when the production from the well declines to a low level. The cycle is repeated until the ratio of oil produced to steam injected (OSR) drops to a level that is considered uneconomic (Ezekwe, 2011). An average of three complete cycles may be used in a single well. Oil recovery per-cycle depends on formation thickness, reservoir pressure, oil in place, volume of steam injected, and the number of preceding cycles. CSS was the first steam flooding technique used in heavy oil reservoirs.

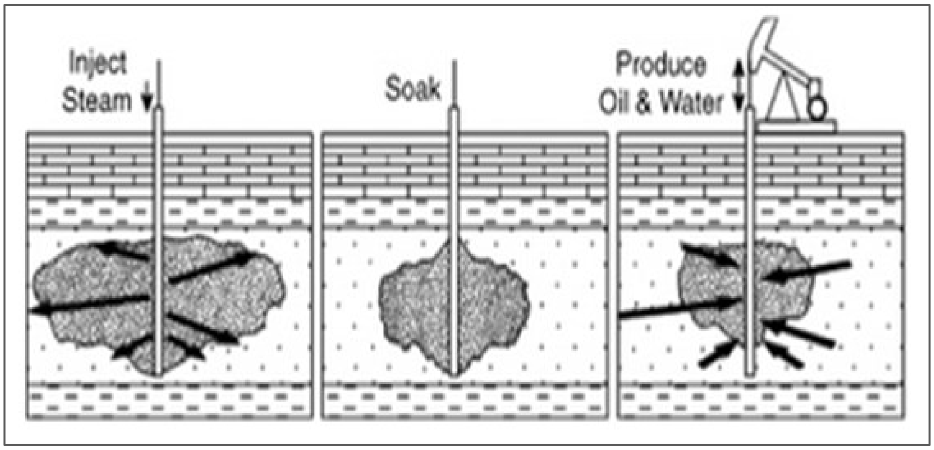

Figure 2.7. Schematic of cyclic steam stimulation process(Ezekwe, 2011)

2.3.3. Steam Assisted Gravity Drainage (SAGD). This process consists of two horizontal wells about 15 feet apart located close to the bottom of the formation. Steam assisted gravity drainage (SAGD) was initially developed to recover bitumen from the Canadian oil sands (Dusseault, 1998). Figure 2.8 shows a schematic of steam assisted gravity drainage process. Steam is injected into the top horizontal well, while the horizontal well below it functions as the producer. The steam creates an expanding steam chamber around the injector as more steam is injected. Within the steam chamber and at its boundaries, as the viscosity of the oil is reduced, its mobility increases causing it to drain under gravity towards the production well.

A key to the process is that the injection to production rates are sufficiently low that the process is dominated by gravity forces. The SAGD process should be applied to reservoirs with formation thickness greater than 50 feet, good vertical permeability, and absence of thief zones. SAGD can be considered as a modification of SD for heavy oil reservoirs including tar sands.

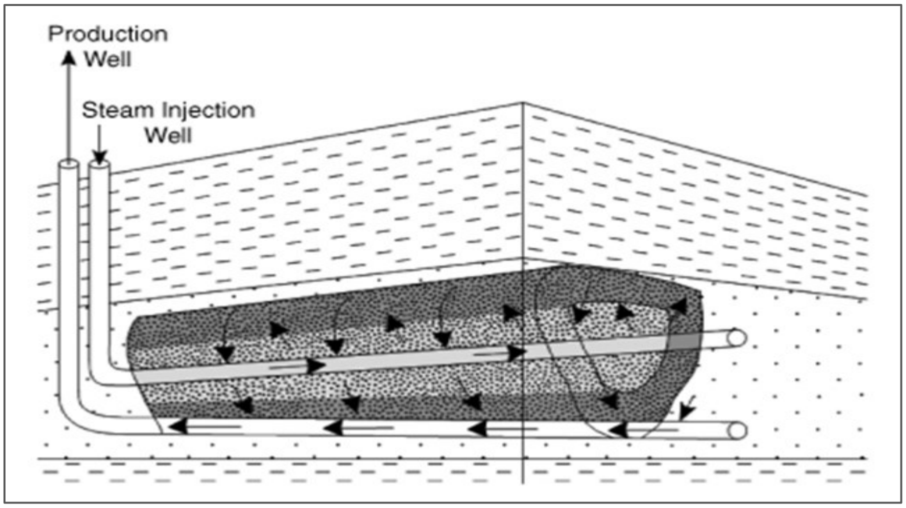

Figure 2.8. Schematic of steam assisted gravity drainage process (Ezekwe, 2011)

2.3.4. In-Situ Combustion (ISC). In this process, heat produces by burning some of the oil within the reservoir rock. Air is injected into the reservoir, and a heater is lowered into the well to ignite the oil. Ignition of the air-crude oil mixture can also be accomplished by introducing into the oil-bearing reservoir rock a chemical that undergoes an exothermic reaction. This process is an attempt to extend thermal recovery technology to deeper reservoirs and or more viscous crudes. The amount of oil burned and the amount of heat created during in-situ combustion can be controlled to some extend by varying the amount of air injected into the reservoir (Hong, K.C., 1994). In recent years it has become known as high-pressure air injection. In-situ combustion recovers 10-15% of the original oil in place.

2.4. ENHACED OIL RECOVERY SCREENING

In the past, screening criteria or guides have been developed and employed to define the candidate reservoirs for each EOR method. Screening criteria are among the first items considered when a petroleum engineer evaluates a candidate reservoir for enhanced oil recovery (EOR). The screening criteria for a specific EOR process consist of a list of reservoir parameters and fluid properties such as oil gravity, oil viscosity, reservoir porosity, oil saturation start and end, reservoir permeability, reservoir depth, reservoir temperature, reservoir pressure and pay thickness and their ranges. The criteria recommend minimum to maximum ranges for each parameter, which are likely to lead to a success.

The nature of the reservoir will play a dominant role in the success or failure of any EOR process. Many of the failures with EOR have resulted because of unknown or unexpected reservoir problems. Therefore, geological study is usually warranted. Some EOR processes can be rejected quickly because of unfavorable reservoir or oil properties, so the use of preferred criteria can be helpful in selecting methods that may be commercially attractive (Taber 1997).

Where two processes are equally suited to any set of conditions, an economic study must be performed to determine which is cheaper or which will recover more oil. Screening guides are provided to help engineers in deciding which particular recovery process might be most applicable for a given set of conditions (Iyoho, 1978).

Screening Criteria has been developed for EOR processes based on filed applications and laboratory tests. In addition to these conventional screening criteria, nowadays computer programming and machine learning are also employed to cover a wider range of data. The complexity of defining an oil reservoir's important parameters depends largely on the availability and quality of input data; therefore, these descriptions can result in a high degree of uncertainty.

Some software has been developed to perform screening based on a different number of EOR methods, among these softwares are: EORgui, Sword, SelectEOR™, PRIze™, Screening 2.0 and IORSys. Trujillo (2010) developed a software based on Screening 2.0, which executes screening criteria of nineteen EOR methods. Gharbi (2000) proposed an expert system for selecting and designing EOR processes. He applied an artificial intelligence (AI) technique to select and design the EOR processes. The expert system was able to select an appropriate EOR process on the basis of the reservoir characteristics.

The main problem for using these machine-learning methods is the lack of quality data. Sufficient number of data sets must be available so that the expert system can be trained to find a relationship between different complex reservoir properties and the potential of each EOR method.

2.5. SUMMARY SCREENING CRITERIA FOR STEAMFLOODING

Over the last few decades, many researchers have developed and published screening criteria for steam flooding. Table 2.1 shows the screening criteria for steam flooding published by different researchers from 1973 to 2010.

Table 2.1. General screening guide for steam flooding

Author	Year	°API	μo cp	ø %	S_o start, %	K md	T °F	D ft.	h ft.
Geffen	1973	>10				**	**	<4000	>20
Farouq Ali	1974	12-25	<1000	≥30	1200-1700 bbl/ac-ft	~1000		<3000	≥30
Lewin & Assocs	1976	>10	NC		>50	NC	NC	<5000	>20
Iyoho	1978	10-20	200-1000	≥30	>50	>1000		2500-5000	30-400
Chu	1985	<36		>20	>40			>400	>10
Brashear & Kuuskraa	1978	>10	NC		42	NC	NC	<5000	>20
Taber & Martin	1997	8-25	<100,000		>40	>200	NC	<5000	>20
Dickson	2010	8-20	1,000-10,000		>40	>250		400-4500	15-150
Aladasani & Bai	2010	8-30	5E6-3	12-65	35-90	1-15000	10-350	200-9000	>20

NC= Not critical.
* Requires laboratory test to confirm suitability.

Geffen (1973) provided criteria based on information reported from laboratory and field studies. Farouq Ali (1974) derived general screening criteria for steam flooding based on data correlations for 16 selected field tests reported in the literature. Lewin and Associates (1976) developed a screening guide for five major EOR methods based on consultations with authorities in the EOR field and on the review and analysis of literature and field reports of actual EOR projects. Iyoho (1978) published screening guides for various EOR processes based on the range of values of each parameter in over 200 fields, as reported in the literature. Brashear and Kuuskraa (1978) used data collected from 200 EOR pilot projects in the U.S. to develop screening criteria by analyzing the data from both a technical and an economic perspective. Chu (1985) developed a screening guide based on 28 detailed steam flooding projects in the U.S., the Netherlands, Venezuela and Germany. Taber (1997) proposed screening criteria based on field data and oil recovery mechanisms for common EOR techniques, considering the 1996 Worldwide EOR Survey to summarize the criteria. Dickson et al. (2010) proposed criteria based on a combination of experience and values published in the literature. Aladasani and Bai (2010) updated the EOR criteria developed by Taber et al. in 1996 based on EOR field application data reported in the EOR surveys published in the *Oil and Gas Journal* from 1998 through 2008.

3. STEAM FLOODING

Steam flooding is an established EOR technique that has been applied on many heavy oil reservoirs around the world. The process started in early 1960 with cyclic steam injection in the Tia Juana Field in Venezuela (Ezekwe, 2011). Recovery by steam flooding is commonly used in heavy-oil reservoirs containing oil whose high viscosity is a limiting factor for achieving commercial oil-producing rates.

Steam flooding also referred to as continuous team injection and steam drive, steam is injected continuously through one well, or set of wells, while oil is produced through a different well, or set of wells, in a manner similar to conventional water injection operation. High-temperature steam is continuously injected into a reservoir. As the steam loses heat to the formation, it condenses into hot water, which, coupled with the continuous supply of steam behind it, provides the drive to move the oil to production wells. In steam flooding, the injected steam not only serves to lower the oil viscosity, but also supplies the drive energy (Farouq Ali, 1974).

3.1. STEAM FLOODING MECHANISMS

Steam flooding uses both injection and production wells to improve the rate of production and the amount of oil that will ultimately be produced. The injected steam reduces the viscosity of the oil and pushes the oil from injector to producer. As steam moves through the reservoir between the injector and producer, it typically creates five different regions of temperatures and fluid saturations. Figure 3.2 shows typical steam flooding temperature and saturation profile.

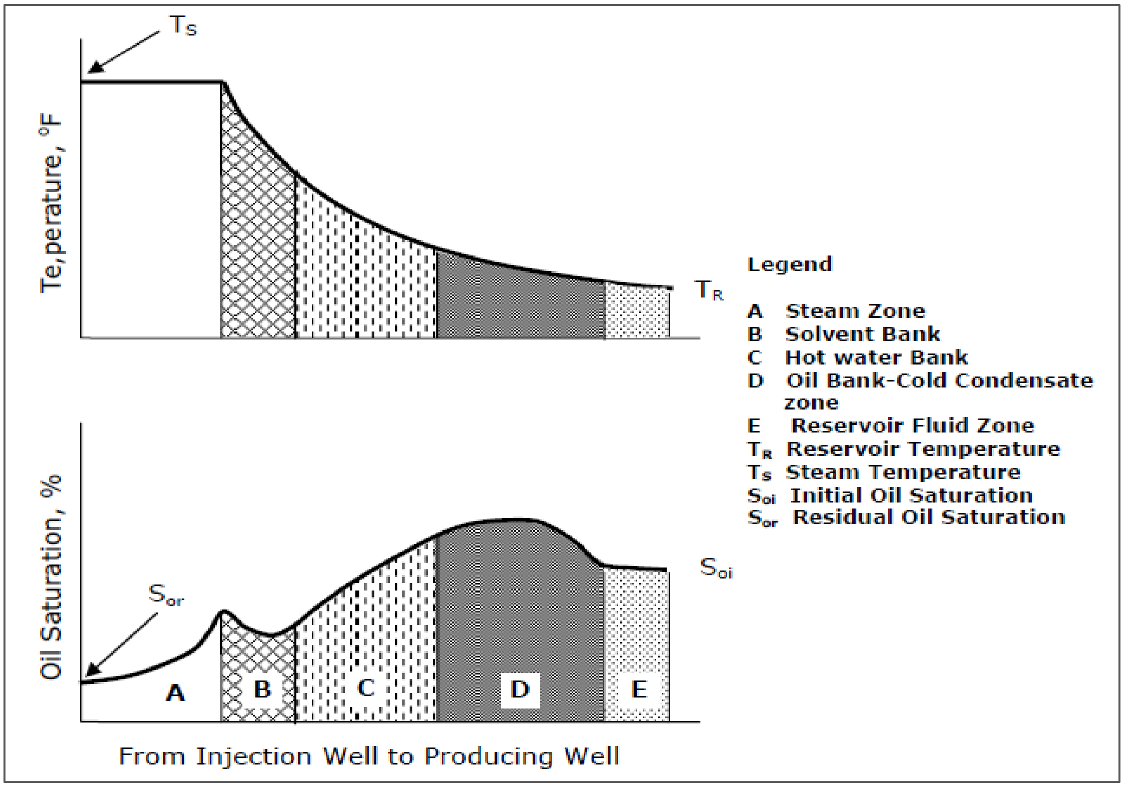

Figure 3.1. Temperature and saturation profile for steam flooding (K. C. Hong, 1994)

As steam enters the reservoir, it forms a steam saturated zone around the wellbore. This zone, at about the temperature of injected steam, expands as more steam is injected. Ahead of the steam saturated zone (A), steam condenses into water as it loses heat to the formation and forms a hot condensate zone (B, C). Pushed by continued steam injection, the hot condensates carries some heat ahead of the steam front into the cooler regions further from the injector. Eventually, the condensate loses its heat to the formation, and its temperature is reduced to the initial reservoir temperature.

Because different oil displacement mechanisms are active in each zone, oil saturation varies between injector and producer. The active mechanism and hence, the saturation depend mainly on thermal properties of the oil. In the steam zone (A), oil saturation reaches its lowest value because the oil is subject to the highest temperature.

The actual residual saturation achieved is independent of initial saturation but rather depends on temperature and crude oil composition. Oil is moved from the steam zone to the hot condensate zone (B, C) by steam distillation at the steam temperature, creating a solvent bank (B) of distilled light ends just ahead of the steam front. Gas is also stripped from the oil in this region.

In the hot condensate zone, the solvent bank (B) generated by the steam zone extracts additional oil from the formation to form an oil-phase miscible drive. The high temperature in this zone reduces the oil viscosity and expands the oil to produce saturations lower than those found in a conventional waterflood.

The mobilized oil is pushed ahead by the advancing steam (A) and hot water (C) fronts. By the time the injected steam has condensed and cooled to reservoir temperature (in the cold condensate zone), an oil bank (D) has formed. Thus, oil saturation in this zone is actually higher than initial oil saturation. Displacement here is representative of a waterflood. Finally, in the reservoir fluid zone (E), temperature and saturation approach the initial conditions (K. C. Hong, 1994).

The decrease in oil viscosity (μ_o) with increasing temperature is the most important mechanism for recovering heavy oils. With lower oil viscosity, the displacement and area sweep efficiencies are improved. As the reservoir temperature increases during steam injection, the viscosity of oil (μ_o) decreases. The viscosity of water (μ_w) also decreases, but to a less degree. The net result of increasing temperature is to improve the water-oil mobility ratio (M), defined as ($M = \mu_o k_w/\mu_w k_o$). Where k_w and k_o are the effective permeability to water and oil, respectively.

3.2. APPLICATION CONDITION OF STEAMFLOODING

Steam flooding applications are restricted (limited) for the following (Lyons & Plisga, 2005):

1. Oil saturation must be quite high and the pay zone should be > 20 feet thick to minimize heat losses to adjacent formations.
2. Lighter, less viscous crude oils can be steam flooded if they don’t respond to water flood.
3. Steam flooding is primarily applicable to viscous oil in massive, high permeability sandstone or unconsolidated sands.
4. Steam flooded reservoirs should be shallow as possible as long as pressure for sufficient injection rates can be maintained due to the excessive heat losses in the wellbore.
5. Steam flooding is not normally used in carbonate reservoirs.
6. The cost per incremental barrel of oil is high because approximately one-third of the additional oil recovered is consumed to generate the required steam.
7. A low percentage of water-sensitive clays are desired for good injectivity.

3.3. CHALLENGING FACED TO STEAMFLOODING APPLICATION

Major problems facing steam flooding are the following:

a) Adverse mobility ratio and channeling of the steam through high permeability zones, because steam is lighter and more mobile than oil.

b) Gravity override occurs in most steam floods, with low density steam rising to the top of the formation. This leads to early breakthrough and reduces the amount of contacted oil in the reservoir, only heating the upper portion of the reservoir. The oil that is directly below it is not heated. Accumulation of steam on the top portion of the reservoir causes heat losses to the overburden. Therefore the portion of reservoir that is swept by steam has low residual oil saturation whereas the bottom part of the reservoir has significantly higher oil saturation (Green & Willhite, 1998).

3.4. DESIGN STEAMFLOODING PROJECT

Design of a steam flood field project involves the choice of pattern type and size, steam injection rates and quality and completion intervals of injectors and producers. Many of earlier steam flood projects were based on engineering judgment and experience. Since the advent of the three-dimensional (3D), three-phase numerical models, an increasing number of steam flood projects have been designed by numerical simulation. In addition, physical models were used for the design of steam flood projects. The design of any field project requires a correlation of its economics and its requirements for technical success (K. C. Hong, 1994).

The following should be considered in designing any field project (Prats, 1986):

1. Is the reservoir description adequate?
2. Is there enough oil in place to justify the effort?
3. Can the old wells be used for thermal operations?
4. Are there adequate sources of fresh water and fuel?

5. Is there sufficient information to estimate the likely range of operating variables (such as pressure and rates and injectors and producers) and production performance?

3.5. FACTORS TO BE CONSIDERED WHEN DESIGNING PROJECTS

Steamflooding depends upon the following parameters (Donaldson et al., 1989):

1. Alteration in the fluid properties in situ. These comprise changes in phase behavior, densities, viscosities, composition, compressibilities, and P-V-T relationship.
2. Rock properties such as absolute permeability, porosity, rock compressibility and the attendant changes in these properties on the injection of steam.
3. Properties related to fluid-rock interaction. These include residual saturations (related in turn to wettability, interfacial tension, etc.) relative permeability, capillary pressure and their dependence upon temperature.
4. Thermal properties of the formation and contained fluids, such us specific heat, thermal conductivities, thermal expansion coefficient and changes induced in these.
5. The reservoir environment: net/gross (presence of shale barriers, etc.), heterogeneity, properties of the overburden and underburden, the initial oil saturation, temperature and pressure.
6. Flood geometry: pattern shape and spacing, producing-injecting interval (well completion) location and thickness.
7. Parameters within the operator’s control such as steam injection rate, steam quality, injection pressure and temperature, cumulative amount of injection.

After the conditions (design criteria) under which steam flood projects are successful. Many other factors must be taken into account in designing a steam project. Some of these are:

1) Reservoir rock mineral content.
2) Availability of fuel and water.
3) Crude analysis, especially if the lease crude is used as steam generator fuel.
4) Required water treating.
5) Size of water handling equipment.
6) Production facilities to handle hot fluids.
7) Sand and possibly emulsion.
8) Condition of existing wells.
9) Surface piping.
10) Availability of light oil for downhole blending, if required.
11) Markets and transportation facilities for the heavy crude produced.
12) Compliance with the local safety and environmental pollution regulation.

3.6. STRATEGY OF STEAMFLOOD DEVELOPMENT

A steam flood project typically proceeds through four phases of development:

1. Reservoir screening. The first step in developing a steam EOR project is to screen candidate reservoirs for potential application of the method using as many reservoir and geological parameters as available. If sufficient reservoir information is available, a scoping study is carried out to define the potential

economic of the project. If the study shows that sufficient oil can be recovered economically to justify a full-scale project, then a pilot field test is proposed.

2. Pilot tests. It is a small scale usually involving one or more patterns located in a representative area of the candidate reservoir or field. It is carried out to generate the information needed. Following the pilot test, if the decision is to proceed, a plan of implementation must be developed.
3. Field wide implementation. This phase is usually accomplished by adding patterns adjacent to the pilot in stages until all of the target area is incorporated into the project. The reservoir model constructed during the pilot test phase of development. Is used to optimize the project expansion and operation.
4. Performance monitoring, analysis and modification. Reservoir management. Performance prediction is essential to provide information for proper execution of each of these development phases. Three different mathematical models (statistical, numerical, and analytical models) are commonly used to predict steam flood performance. This phase of development includes maintaining and updating reservoir description, monitoring and analyzing project performance, and modifying project operations as necessary.

4. DATA COLLECTING AND CLEANING

4.1. DATA COLLECTION

A dataset was created by collecting steam flooding field project data from the Worldwide EOR Survey biennially published in the *Oil & Gas Journal* from 1980 to 2012. The original dataset included a total of 1,785 steam flooding field projects from all over the world. Figure 4.1 shows the number of steam flooding projects, thermal projects (steam, in-situ combustion and hot water) and total EOR projects (thermal, chemical, gas and others, such as microbial) applied in the U.S. from 1971 to 2012.

Figure 4.2 illustrates the oil production from steam flooding projects in the U.S. from 1980 to 2012. From 1978 to 1986, the number of thermal projects rose each year in the U.S., but it has been on the decline since 1988. Between 1984 and 1986, the number of steam flooding projects increased by 36.1% (Leonard, 1986). On the contrary, the number of steam flooding projects decreased drastically between 1986 and 1988 because 48 projects were shut down due to low crude prices (Aalund, 1988). From 1990 to 2006, the number of projects continued to decline due to decreasing crude prices. However, thermal projects have increased slightly since 2008.

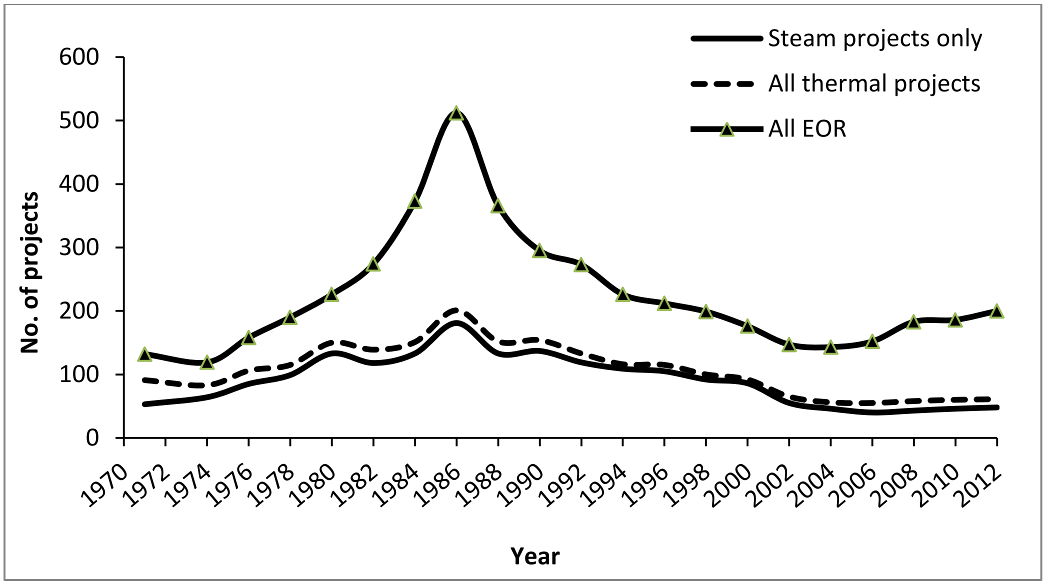

Figure 4.1. Number of active EOR projects in the U.S., as reported in the Worldwide EOR Survey from 1971 to 2012 (from *Oil & Gas Journal* EOR surveys 1980-2012)

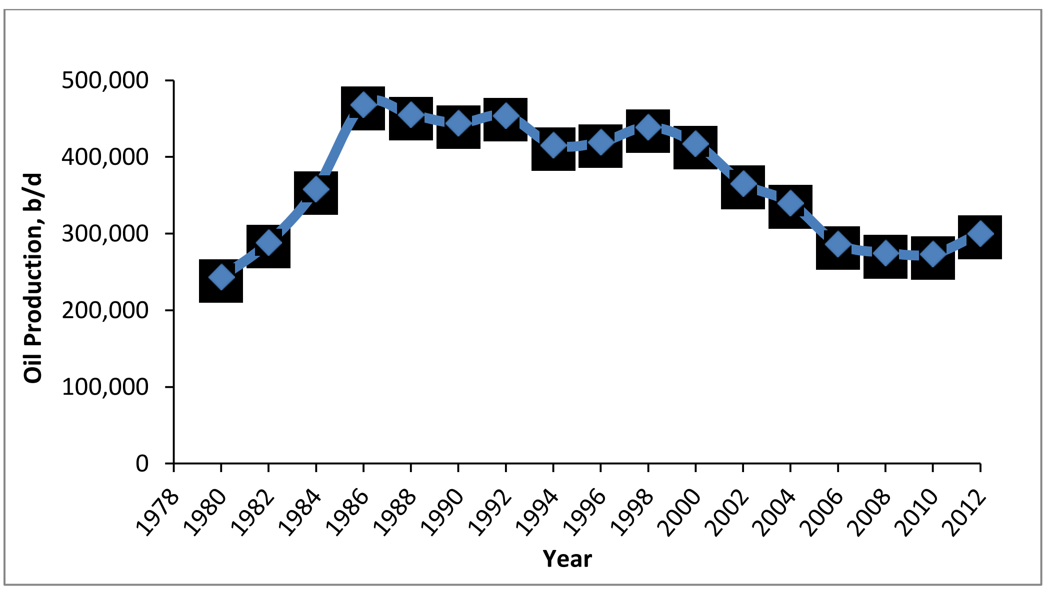

Figure 4.2. Oil production from steam flooding projects in the U.S. from 1980 to 2012 (from *Oil & Gas Journal* EOR surveys 1980-2012)

4.2. DATA CLEANING

Data quality is essential to ensuring the validity of screening criteria results. EOR survey data contain many types of problems that can affect the quality of the dataset, in particular, duplicate projects, missing data, inconsistent data and outliers.

4.2.1. Duplicate Data. The duplicate data problem was observed while collecting data from the worldwide EOR surveys. Many fields were listed more than once with the same values in different years of publication. This duplication may have occurred because some countries may not have updated their EOR information for several years (Moritis, 2002, 2004, and 2008), and the EOR survey did not change their records. However, to solve the problem with duplicate data from earlier surveys, duplicate projects (the same projects published in different years) were detected and deleted from the dataset. After removing the duplicates, 626 projects remained in the dataset.

Figure 4.3 shows the distribution of the steam flooding field projects applied in different countries. Approximately 65% of all steam flooding projects have taken place in the U.S. The formation types to which steam flooding can be applied include sandstone, unconsolidated sand, limestone, dolomite, tripolitic, fractured Chert-dolomite, sandstone/conglomerate, sandstone/dolomite and shale. Figure 4.4 shows the steam flooding field projects by lithology. As shown, approximately 84% of projects were applied in sandstone formations, 8% in unconsolidated sand formations, 1% in carbonate formations, 1% in other formations, such as shale, tripolitic and mixed formations, and 6% in unknown formations (formation data were not available).

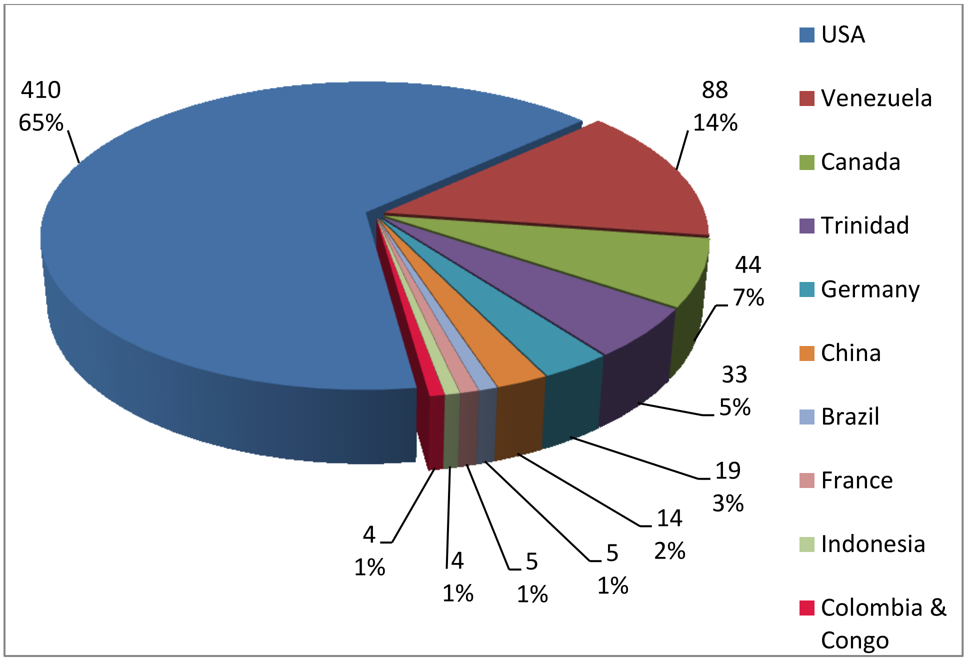

Figure 4.3. World steam flooding projects (from *Oil & Gas Journal* EOR surveys 1980-2012)

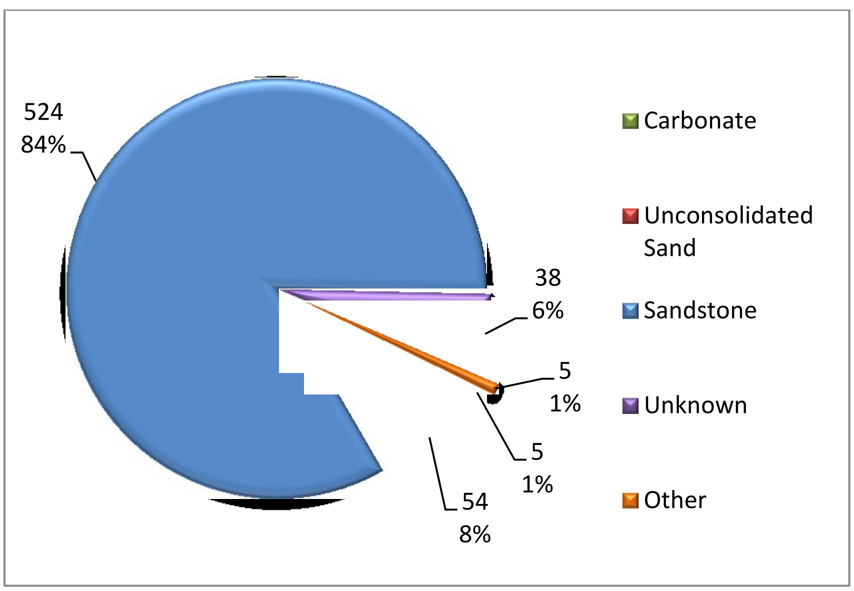

Figure 4.4. Steam flooding field projects by lithology (based on 626 projects)

Each field project in the dataset was placed into one of the following categories based on its level of success: too early to tell, promising, successful, discouraging and unevaluated. An EOR process was deemed successful only if it was both an engineering and an economic success. To update the screening criteria, only data from successful and promising projects were used for statistical analysis. Fig. 4.5 shows the number and type of accepted projects; projects in the other categories were removed from the dataset to ensure its quality before running the analysis.

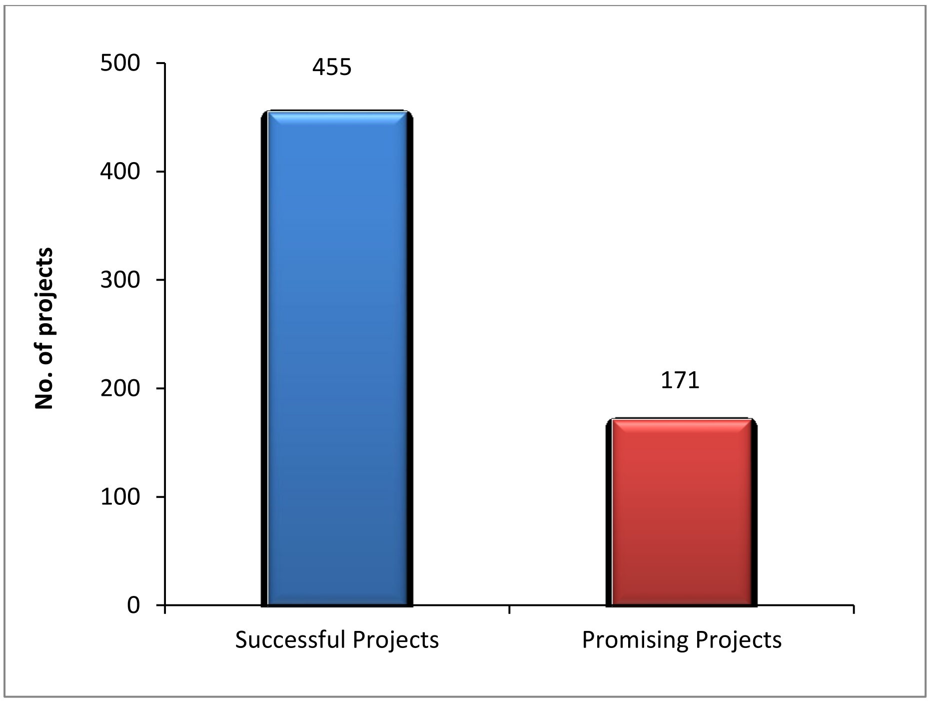

Figure 4.5. Accepted steam flooding field projects

4.2.2. Missing Data. Some fields within the dataset were missing one or more pieces of information, including oil saturation (start and end), viscosity, permeability, depth, oAPI gravity, porosity, formation type and temperature. Table 4.1 lists the number of missing pieces of data for each parameter and the percentage of missing data to all data. These missing values were ignored during the analysis.

Table 4.1. Data unavailable for each parameter of the projects in the dataset

Parameter	Data available for No. of projects	Data unavailable for No. of projects	Data missing percentage
Formation type	588	38	6.1%
Porosity	617	9	1.4%
Permeability	568	58	9.3%
Reservoir depth	622	4	0.6%
Oil gravity (°API)	623	3	0.5%
Oil viscosity	602	24	3.8%
Reservoir temperature	593	33	5.3%
Oil saturation (Start)	544	82	13.1%
Oil saturation (end)	409	217	34.7%

4.2.3. Inconsistent Data. Data are considered inconsistent if they contain either discrepancies or impossible values. Several pieces of information in the dataset were inconsistent, such as:

- Oil saturation (end) > oil saturation (start).
- Oil saturation (start) equal to 100%.
- Oil saturation (end) equal to 100%.
- Oil saturation (start) < 10%.
- Porosity > 50%.

Most of the inconsistent data and outliers were detected by box and cross plots.

4.2.4. Data Problem Detection. A box plot is a highly visually effective way of viewing a summary of the data. It is particularly useful for quickly summarizing and comparing the results. It consists of a center line (the median) splitting a rectangles defined by the upper and lower hinges, as depicted in Figure 4.6. Describing the following six numbers yields a summary of the data:

1) The lowest value (minimum).

2) The highest value (maximum).

3) The mean (average) of the data.

3) The first quartile (25th percentile).

4) The second quartile (50th percentile).

5) The third quartile (75th percentile).

Outliers are larger than the upper limit of the data and smaller than the lower limit. The upper limit is calculated as 1.5 times the interquartile range plus the 75th percentile, and the lower limit as 1.5 times the interquartile range minus the first 25th percentile. Fig. 4.6 shows a schematic diagram of the box plot. The two rectangles represent the first to the third quartiles (25th to 75th percentiles, respectively). The median of the dataset appears in the center (horizontal line), and the mean is indicated by the orange circle. The end of both whiskers represents the minimum and maximum dataset observations.

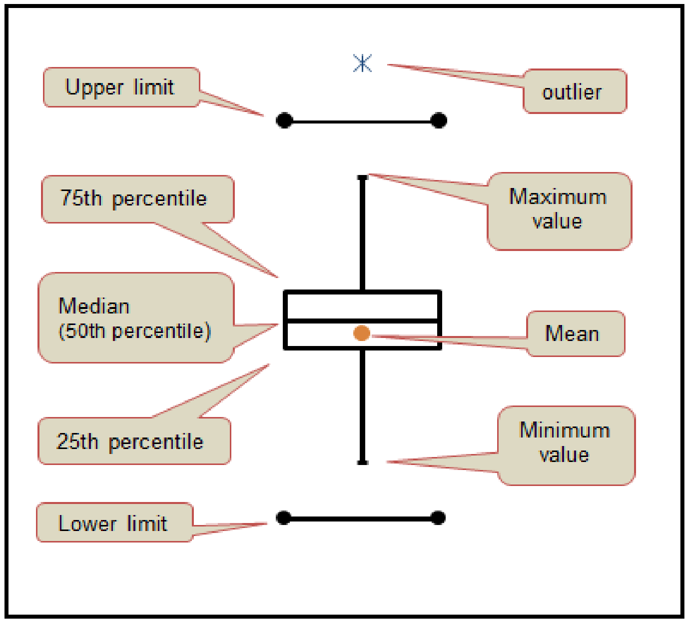

Figure 4.6. Schematic diagram of box plot with outlier

A cross plot was used to plot a pair of variables from the dataset. The plot helped to reveal the relationships between these variables and to detect outliers. The box and cross plots were combined to yield additional clarity.

Temperature vs depth. Figure 4.7A shows the cross plot of the temperature vs. the depth, and Figure 4.7B shows the box plot for the reservoir temperature of the dataset. The box plot illustrates that the temperature data from several fields exceeded the upper limit (black line, 140 ^{o}F) of the dataset. The reservoir temperatures in these fields exceeded 200 ^{o}F and also were inconsistent with the corresponding reservoir depths, as shown in the crossplot. These projects have been circled and marked as outliers. Both the cross plot and box plot show a few projects with very low temperatures. We consider these data to have been recorded in error when reported in the *Oil & Gas Journal*. These data also have been circled and marked as outliers. Table 4.2 lists the outlier projects.

Figure 4.7C shows the box plot for the reservoir depth of the dataset, which indicates that the depth data from several fields exceeded the upper limit (black line, 3,000 ft). These data were not considered outliers, however, because the reservoir depth and other field parameters, such as the temperature, were consistent for these projects.

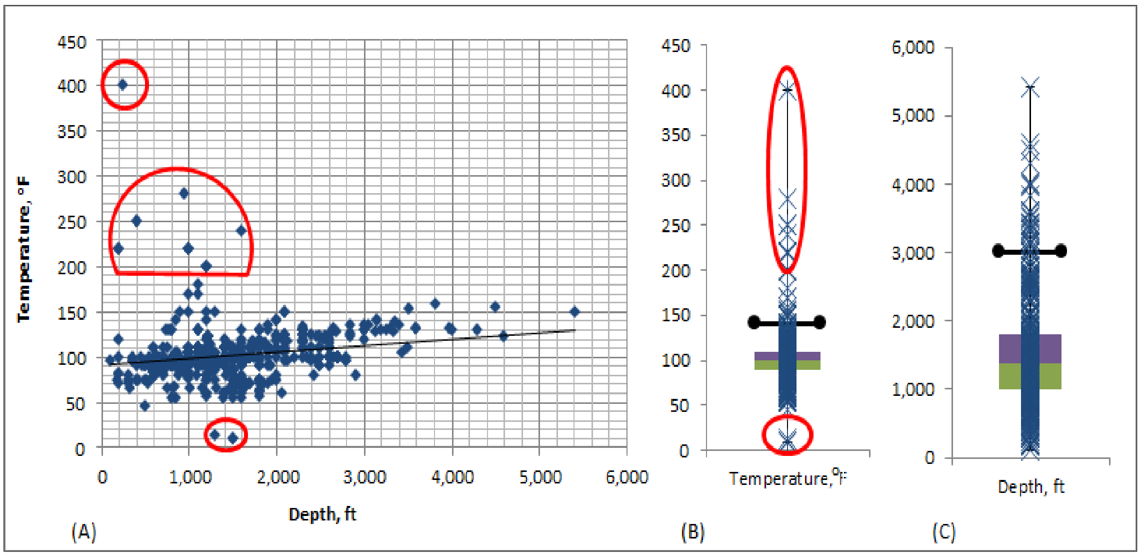

Figure 4.7. (A) Cross plot of temperature vs. depth, (B) Box plot of temperature, (C) Box plot of porosity

Table 4.2. Outlier projects of the dataset for reservoir temperature

Started year	Field name	Country	Formation Type	ø %	K md	D ft	Gravity °API	μ_o cp	T °F	S_o start	S_{or} end	Project evaluation	Reporting year
1972	Athabasca	Canada	Unconso.	34.0	250.0	250.0	8.0	10.0	400.0	100.0		Promising	1980
1977	Midway-Security	USA	Unconso.	33.0	5,000.0	950.0	12.0	1,500.0	280.0	60.0	20.0	Successful	1990
1977	Lost Hills	USA	Sandstone	40.0	2,000.0	400.0	13.0	10.0	250.0	63.0	30.0	Successful	1986
1977	Lost Hills	USA	Sandstone	40.0	2,000.0	400.0	13.0	250.0	250.0	63.0	30.0	Successful	1998
1984	Midway-Sec 35	USA	Unconso.	35.0	2,000.0	1,600.0	12.0	1,500.0	240.0	55.0	20.0	Successful	1990
1977	Lost Hills	USA	Sandstone	38.0	2,000.0	200.0	13.0	20.0	220.0	70.0	30.0	Successful	1986
1981	North Midway	USA	Unconso.	30.0	3,400.0	1,000.0	13.0	1,500.0	220.0	60.0	20.0	Successful	1990
1984	Mckittrick	USA	Sandstone	38.0	2,800.0	1,000.0	13.0	35.0	220.0	60.0	30.0	Promising	2002
1975	Lost Hills	USA	Sandstone	38.0	2,000.0	200.0	13.0	20.0	220.0	70.0	30.0	Successful	1998
1977	Midway-Sunset	USA	Sandstone	24.0	1,500.0	1,000.0	11.3	100.0	220.0	55.0	34.0	Successful	1998
1981	Midway-Sunset	USA	Sandstone	30.0	3,000.0	1,200.0	13.0	30.0	200.0	45.0	20.0	Successful	1986
1973	Midway-Sunset	USA	Sandstone	32.0	1,500.0	1,200.0	13.0	3,000.0	200.0	50.0	10.0	Successful	1990
1981	Midway-Sunset	USA	Sandstone	32.0	1,500.0	1,200.0	13.0	30.0	200.0	50.0	10.0	Successful	1992
1983	Midway-Sunset	USA	Sandstone	30.0	2,000.0	1,500.0	13.0	5,000.0	10.0	60.0	30.0	Successful	1992
1983	Midway-Sunset	USA	Sandstone	30.0	2,000.0	1,500.0	13.0	5,000.0	10.0	60.0	15.0	Successful	2000
1980	Midway-Sunset	USA	Sandstone			1,300.0	13.0	5,000.0	13.0			Successful	1986

Porosity vs depth. The cross plot in Figure 4.8A shows the relationship between the reservoir porosity and depth. The box plot in Figure 4.8B shows the reservoir porosity ranges for the dataset. The porosity of six fields exceeded the upper limit in the box plot. The upper limit is represented by a black line and equals approximately 42.5%. These fields also appear on the cross plot, where they have been outlined with a square. Table 4.3 lists the outlier projects. The porosities of these outlier fields ranged from 58-65%. These projects were applied in shale and tripolitic formations, though two projects contained no formation type data. These can be considered special cases for porosity ranges because shale and tripolitic formations are known to have high porosity and low permeability.

On both the cross plot and the box plot, one field (Jesus Maria field, USA) had a porosity of 7.5%, the lowest in the dataset, and a depth of 3500 feet. The project began in 1982 and has been successful.

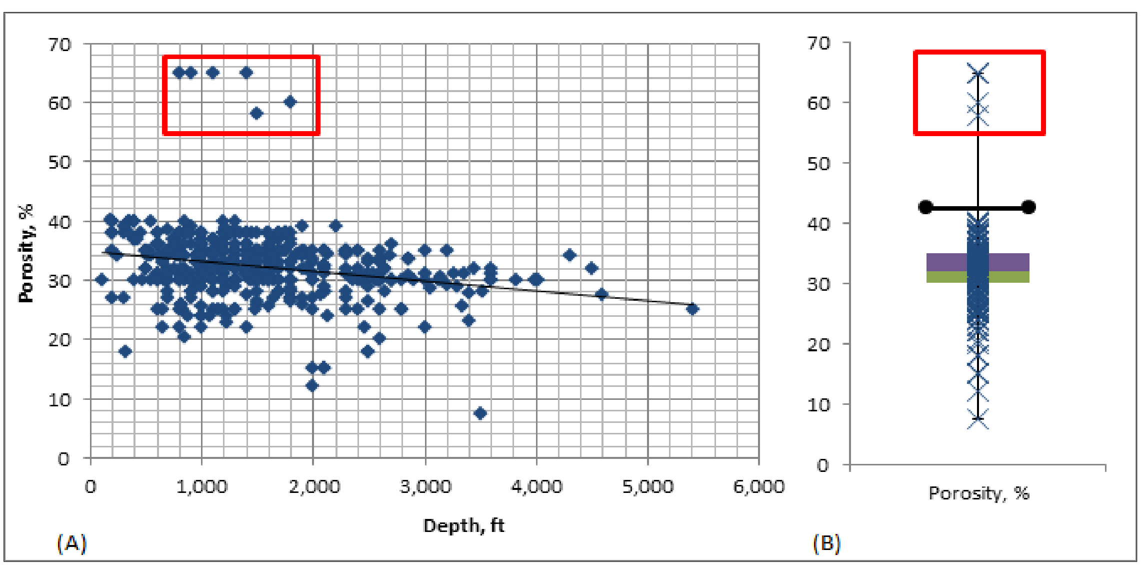

Figure 4.8. (A) Cross plot of porosity vs. depth, (B) Box plot of porosity

Table 4.3. Outlier projects of the dataset for reservoir

Started year	Field name	Country	Formation Type	ø %	K md	D ft	Gravity °API	μ_o cp	T °F	S_o start	S_{or} end	Project evaluation	Reporting year
1992	Midway-Sunset	USA	Shale	65.0	5.0	900.0	12.0	400.0	150.0	60.0	35.0	Promising	2004
1985	Cymric	USA	Shale	65.0	15.0	1,400.0	12.0		110.0	65.0	55.0	Successful	2004
1997	Midway-Sunset Diatomite	USA		65.0	5.0	1,100.0	12.5	1,000.0	90.0	75.0		Successful	2010
2006	North Midway-Sunset	USA	Tripolitic	65.0	1.0	800.0	14.0			65.0		Promising	2008
1995	South Belridge	USA	Tripolitic	60.0	5.0	1,800.0	30.0	50.0	110.0	45.0	20.0	Promising	2008
1980	Cymric 1Y	USA		58.0	5.0	1,500.0	13.0		110.0	60.0		Successful	2008

Permeability vs porosity. Figure 4.9A shows the cross plot of the permeability vs. the porosity, and Figure 4.9B shows the box plot for the reservoir permeability of the dataset. The cross plot depicts a good relationship between the reservoir porosity and permeability of the field projects. The plot also shows the projects that we considered as special cases for porosity in Figure 4.8. The box plot indicates that several permeability data points exceeded the upper limit. The upper limit is represented by a black line and equals approximately 6,000 md. These projects were not considered outliers because the parameters, such as the permeability and porosity, were consistent.

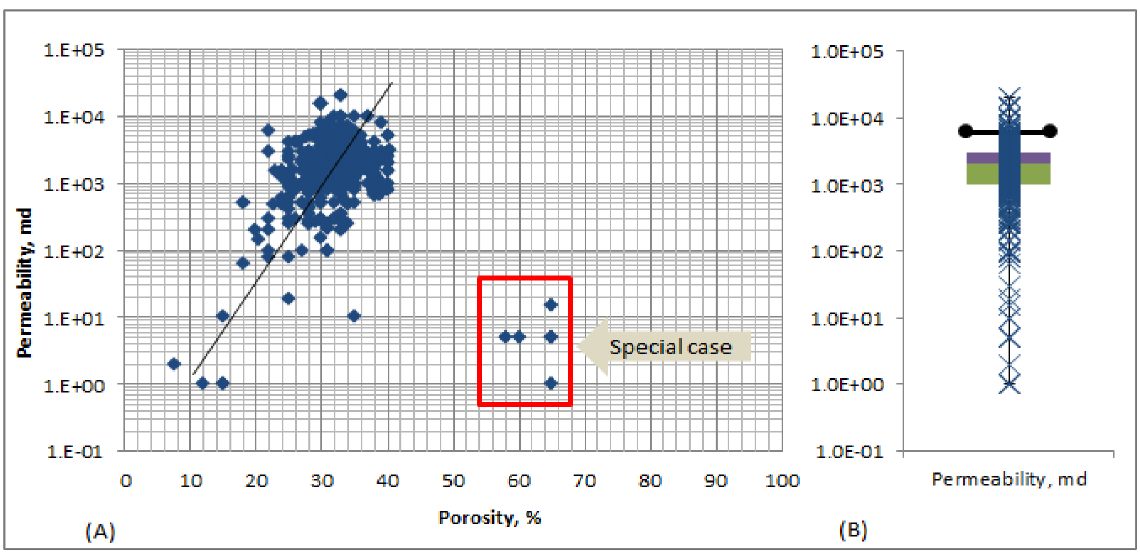

Figure 4.9. (A) Cross plot between permeability and porosity, (B) Box plot of average permeability

Oil gravity vs oil viscosity. The cross plot in Figure 4.10A shows the relationship between the oil gravity and the viscosity, and the box plot in Figure 4.10B shows the oil gravity ranges of the dataset. The cross plot shows a few fields lying far from the majority of the data and exhibiting different behavioral trends. The 10 projects outlined in a square, all implemented in China, thad high oil gravity with high oil viscosity and were considered to be special cases. One project (Athabasca oil field, Canada) appears on the cross plot and lies far from the trend. The project's oil gravity data (8 ^{o}API) and oil viscosity data (10 cp) were inconsistent, so this project has been circled and marked as an outlier. Table 4.4 lists the outlier projects.

The box plot shows that several fields exceeded the upper limit. The upper limit is represented by a black line and equals approximately 17 ^{o}API. These fields were not considered outliers because these data have physical meaning by having high oil gravity and low oil viscosity. The minimum oil gravity recorded in the dataset was 5.8 ^{o}API (Oxnard field, USA), as shown in the box plot.

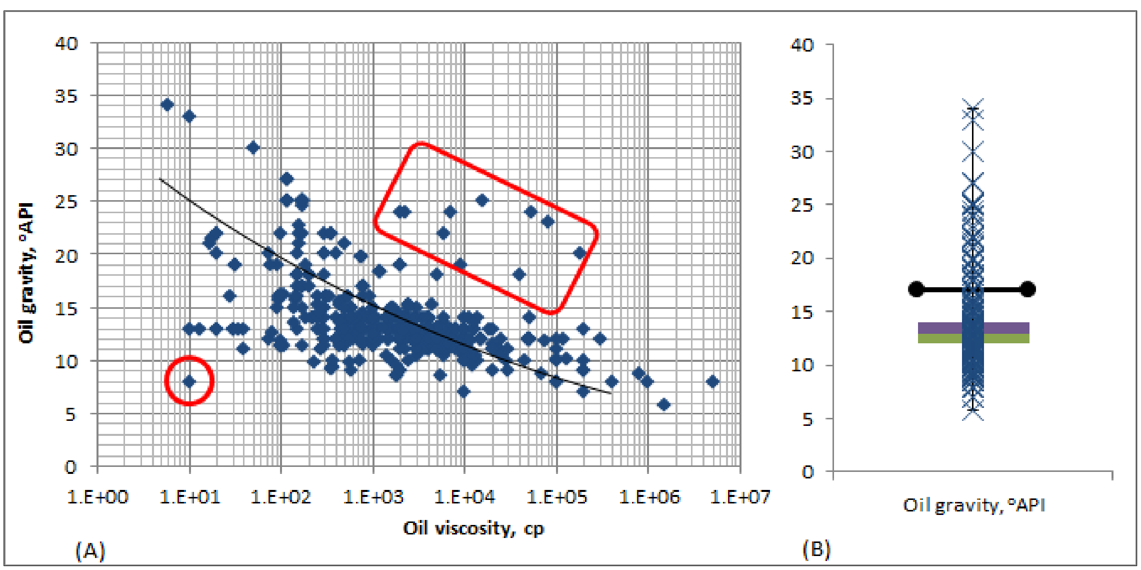

Figure 4.10. (A) Cross plot of oil gravity vs oil viscosity, (B) Box plot of oil gravity

Table 4.4. Outlier projects of the dataset for oil gravity

Started year	Field name	Country	Formation Type	ø %	K md	D ft	Gravity °API	μ_o cp	T °F	S_o start	S_{or} end	Project evaluation	Reporting year
1986	Jinglou	China	Sandstone	32.0	3,000.0	1,936.0	25.0	16,000.0	90.0	73.0		Successful	2008
1984	Karamay 9-1	China	Sandstone	32.0	3,170.0	820.0	24.0	2,000.0	66.0	65.0		Promising	2008
1986	Karamay 9-2	China	Sandstone	32.0	2,290.0	754.0	24.0	2,240.0	66.0	65.0		Promising	2008
1991	Karamay 9-5	China	Sandstone	32.0	2,000.0	1,146.0	24.0	54,000.0	66.0	65.0		Successful	2008
1988	Karamay 9-4	China	Sandstone	30.0	3,000.0	1,312.0	24.0	7,200.0	66.0	65.0		Promising	2008
1989	Karamay 6	China	Sandstone	31.0	3,100.0	1,016.0	23.0	80,000.0	66.0	70.0		Successful	2008
1987	Guenheng	China	Sandstone	34.0	7,134.0	1,627.0	22.0	6,000.0	66.0	65.0		Successful	2008
1984	Shu I 7-5	China	Sandstone	28.0	1,500.0	2,300.0	20.0	180,000.0	134.0	65.0		Successful	2008
1984	Sanjasi	China	Sandstone	30.0	5,000.0	3,983.0	19.0	9,200.0	131.0	60.0		Successful	2008
1989	Lean	China	Sandstone/ Conglomerate	30.0	4,500.0	3,132.0	18.0	40,000.0	129.0	65.0		Successful	2008
1972	Athabasca	Canada	Unconsoli.	34.0	250.0	250.0	8.0	10.0	400.0	100.0		Promising	1980

Oil viscosity vs reservoir temperature. Figure 4.11A shows the cross plot of the oil viscosity vs. the reservoir temperature, and Figure 4.11B shows the box plot for the oil viscosity of the dataset. The oil viscosity values of several fields exceeded the upper limit in the box plot. The upper limit is represented by a black line and equals approximately 12,870 cp. These data were not considered outliers because the other field parameters for the projects, such as the reservoir temperature, oil viscosity and oil gravity, were consistent. However, the cross plot shows five projects that fell far from the majority of the data and the trend. These data have been circled and marked as outliers. Table 4.5 lists the outlier projects. Because the oil gravity and oil viscosity in the Muriel Lake, Newcastle and Midway-Sunset fields were inconsistent, these data were considered outliers.

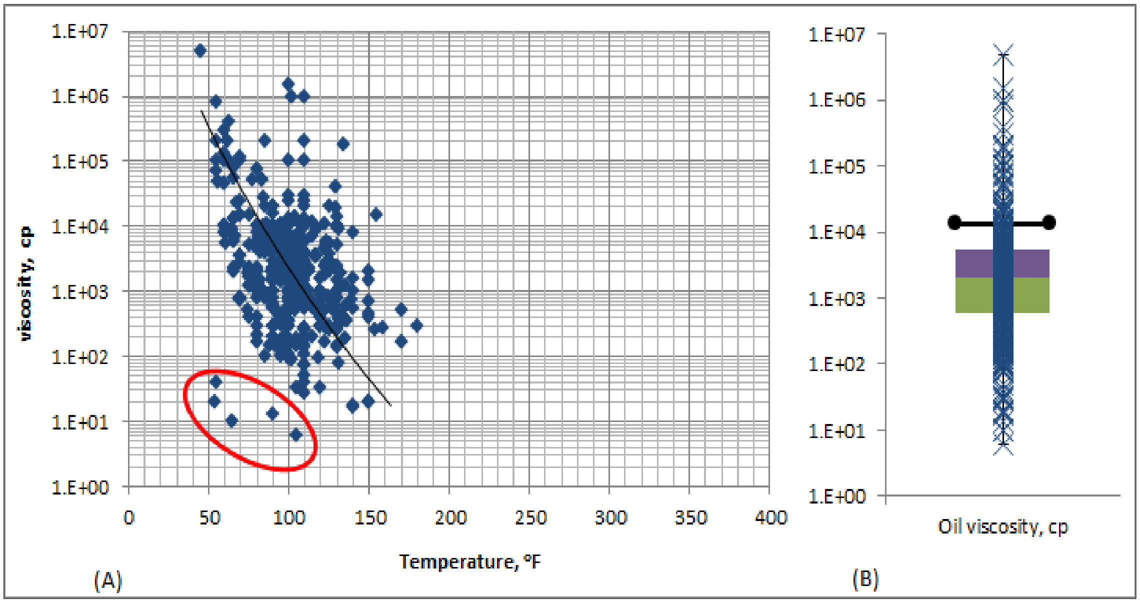

Figure 4.11. (A) Cross plot of viscosity vs temperature, (B) Box plot of oil viscosity

Table 4.5. Outlier projects of the dataset for oil viscosity

Started year	Field name	Country	Formation Type	ø %	K md	D ft	Gravity °API	μ_o cp	T °F	S_o start	S_{or} end	Project evaluation	Reporting year
1981	Muriel Lake	Canada	Sandstone	32	3000		11	40	55	55	45	Promising	1984
2007	Newcastle	USA	Sandstone	22	100	800	20	20	54	85	60	Promising	2008
1965	Midway-Sunset	USA	Sandstone	22	300	1400	13	13.3	90			Promising	1984
1985	Teapot Dome NPR-3	USA	Sandstone	18	63	325	33	10	65	50	15	Successful	1990
1973	Shiells Canyon	USA	Sandstone	20.5	140	850	34	6	105			Promising	1984

Oil saturation (start) vs oil saturation (end). The cross plot in Figure 4.12A shows the relationship between the oil saturation (start) and oil saturation (end). The box plot in Figure 4.12B shows the oil saturation (start) ranges for the field projects in the dataset. The box plot does not show any outliers. The upper limit is represented by a black line and equals approximately 117%. The upper limit exceeded 100% because of the upper limit calculating rule (upper limit = 3rd quartile +1.5 * interquartile). The cross plot shows that several fields had an oil saturation (start) of 100%. Data indicating an oil saturation (start) greater than 96% with previous oil production were considered outliers.

Both the cross plot and box plot show three projects with low oil saturations (start) of 9, 12, and 29%. These points lie far from the majority of the data and have been circled and marked as outliers. Table 4.6 lists the outlier projects.

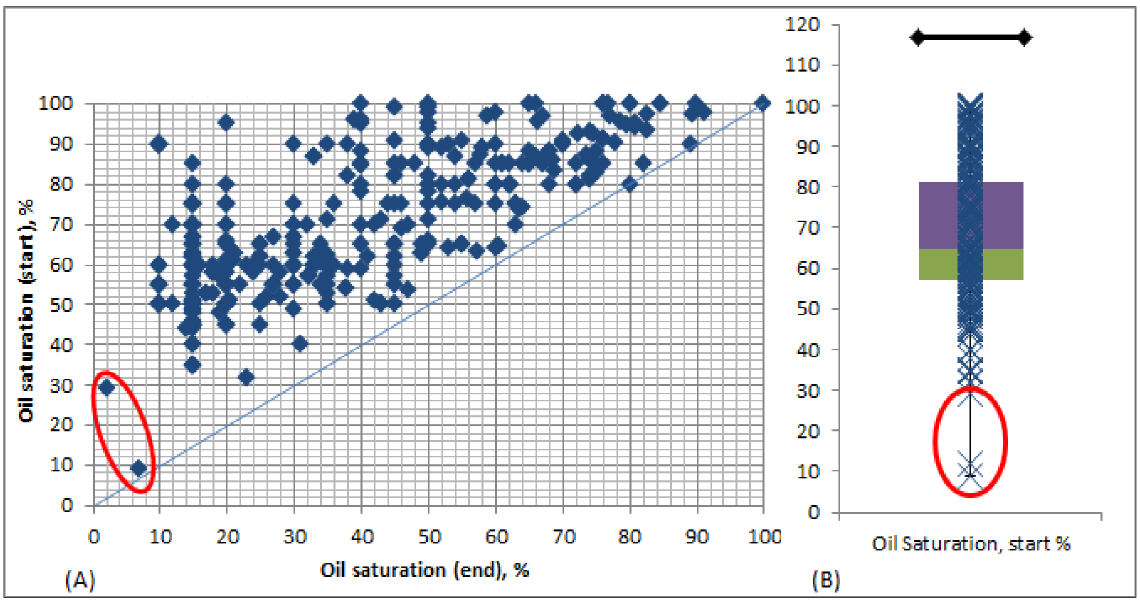

Figure 4.12. (A) Cross plot of oil saturation (start) vs oil saturation (end), (B) Box plot of oil saturation start

Table 4.6. Outliers projects of the dataset for oil saturation

Started year	Field name	Country	Formation Type	ø %	K md	d ft	Gravity °API	μ_o *cp*	T °F	S_o start	S_{or} end	Previous production	Project evaluation	Reporting year
1982	Zuata (heavy oil belt)	Venezuela	Sand.	32.0	2,800.0	d ft	10.0	2,500.0	130.0	100.0	100.0	Primary	Successful	1984
1961	East Tia Juana	Venezuela	Sand.	38.0	1,300.0	1,000.0	9.5	12,000.0	105.0	100.0	76.9	Primary	Promising	1990
1964	Winkleman Dome	USA		24.0	480.0	1,225.0	14.0	900.0	81.0	100.0	50.0	Primary	Successful	1980
1975	Midway-Sunset	USA	Sand.	30.0	2,250.0	550.0	12.0	6,500.0	90.0	100.0	40.0	Cyclic	Promising	1984
1966	NW Polo Seco	Trinidad	Sand.	33.0	2,000.0	1,200.0	12.0	400.0	120.0	100.0		Primary	Promising	1980
1969	East Tia Juana	Venezuela	Sand.	38.1	1,300.0	1,250.0	10.2	12,000.0	102.0	99.9	89.9	Primary	Promising	1990
1969	Main Tia Juana	Venezuela	Sand.	38.1		850.0	10.5	10,000.0	95.0	99.9	84.6	Primary	Promising	1984
1969	East Tia Juana	Venezuela	Sand.	38.1		850.0	10.5	10,000.0	95.0	99.9	84.6	Primary	Promising	1986
1974	White Castle	USA		38.0	3,000.0	1,350.0	16.0	150.0	92.0	99.0	50.0	Primary	Promising	1980
1975	White Castle	USA		38.0	3,000.0	1,000.0	15.0	300.0	90.0	99.0	50.0	Primary	Successful	1980
1975	Lost Hills	USA		38.0	800.0	200.0	14.0	577.0	100.0	99.0	45.0	Primary	Promising	1980
1966	Cymric	USA	Sand.	32.0	1,200.0	700.0	11.0	6,500.0	81.0	99.0		Primary	Successful	1984
1964	Midway-Sunset	USA	Sand.	30.0	1,500.0	1,800.0	12.0	4,000.0	100.0	98.0	60.0	Primary	Successful	1984
1967	Slocum	USA		34.0	3,000.0	520.0	19.0	2,000.0	75.0	98.0	50.0	Primary	Successful	1980
1970	Lagunillas	Venezuela	Sand.	35.0		1,725.0	11.4	9,000.0	118.0	97.8	91.0	Primary	Promising	1984
1968	East Tia Juana	Venezuela	Sand.	38.1		1,250.0	11.7	7,500.0	106.0	97.5	82.5	Primary	Promising	1986
1970	Lagunillas	Venezuela	Sand.	35.0		1,750.0	11.8	11,500.0	115.0	97.3	89.4	Primary	Successful	1984
1974	Brea Olinda	USA		31.0	1,086.0	800.0	12.0	3,100.0	100.0	97.0	77.0	Primary	Successful	1980
1982	Celtic	Canada	Sand.	33.0	700.0	1,500.0	13.0	5,000.0	75.0	97.0	67.0	WC	Promising	1984
1965	Lagunillas	Venezuela	Sand.	35.0		2,100.0	11.4	3,500.0	117.0	96.9	58.7	Primary	Successful	1984
1972	Kern River	USA	Sand.	33.0	4,000.0	1,200.0	13.0	8,000.0	90.0	29.0	2.0	Steam soak	Successful	1986
1985	Fort Kent	Canada	Sand.	35.0		1,000.0	11.0	21,300.0		12.0		None	Promising	1988
1967	Lagunillas	Venezuela	Sand.	35.0		2,100.0	11.4	3,500.0	117.0	9.0	7.0	Primary	Successful	1986

5. DATA ANALYSIS

After removing the duplicate projects from the dataset, the number of steam flooding projects decreased from 1,785 to 626. Figure 5.1 shows the number of studied projects by year before and after cleaning the dataset.

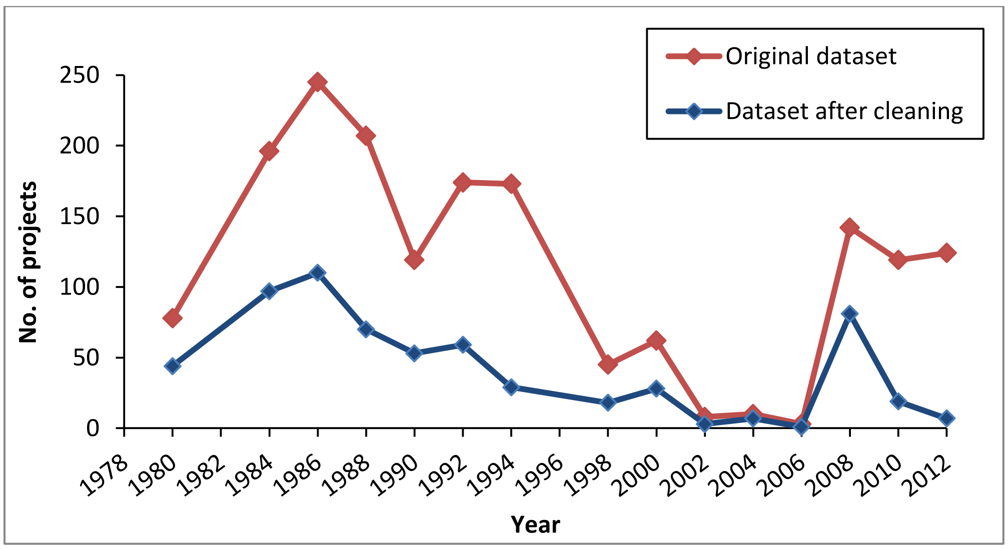

Figure 5.1. Steam flooding projects before and after cleaning the dataset

5.1. METHODS FOR DISPAYING THE DATA

In this work, two types of methods were used to display data. The first type was graphic, including histograms, box plots and cross plots. The second type was statistical methods.

5.1.1. Histograms. Histograms are used to display datasets graphically and show data points in specified ranges. They show the frequency of the data on the y-axis and the variables being measured on the x-axis.

Figure 5.2 shows the reservoir porosity distribution of the dataset, across 611 porosity data points. The distribution is skewed to the left. The minimum porosity is 7.5%, and the maximum is 40.3%. The highest porosity frequency in the distribution is between 29 and 31%. A tail appears on the left side of the distribution, and there is only one field project with a porosity of less than 11%. Approximately 66% of the data points fall between 29 and 35%.

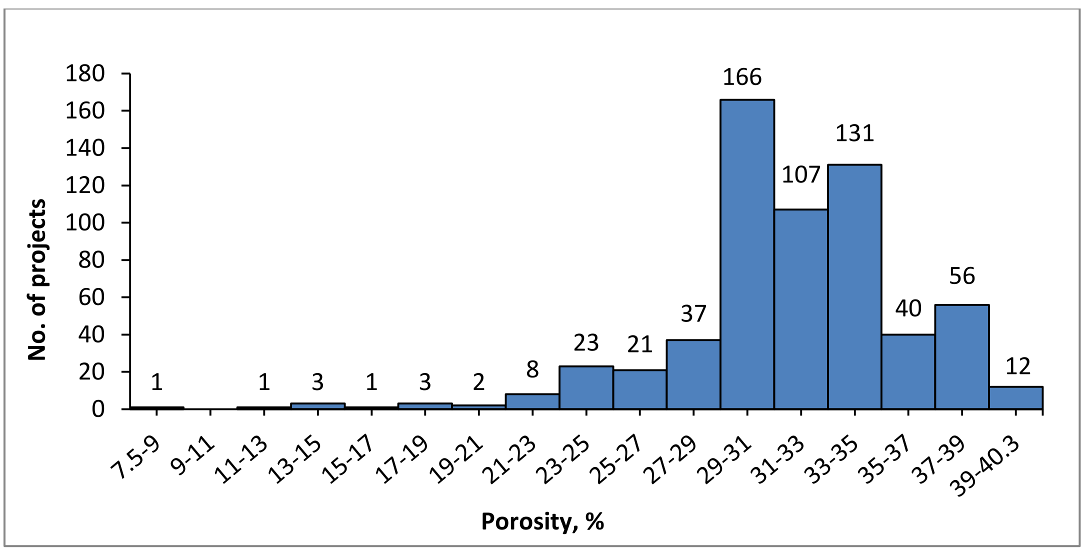

Figure 5.2. Reservoir porosity distributions of the dataset

Figure 5.3 shows the reservoir permeability distribution of the dataset across 568 reservoir permeability data points. The highest peak in the distribution is in the 2,000-3,000 md range. Approximately 94.4% of the data points fall between 100 and 4,000 md.

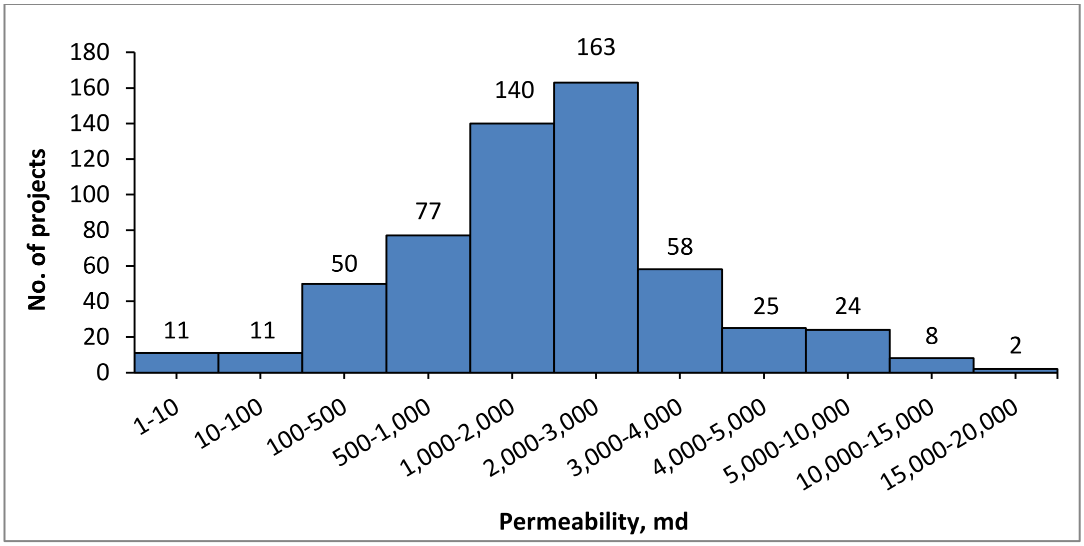

Figure 5.3. Reservoir permeability distributions of the dataset

Figure 5.4 shows the oil gravity distribution of the dataset across 622 oil gravity data points. The distribution is skewed to the right and shows two oil gravity value peaks, one between 10 and 12 ^{o}API and the other between 12 and 14 ^{o}API. These peaks represent roughly 73% of the data. The distribution shows that steam flooding projects were mostly applied in reservoirs with oil gravity between 8 and 26 ^{o}API (heavy and medium oil).

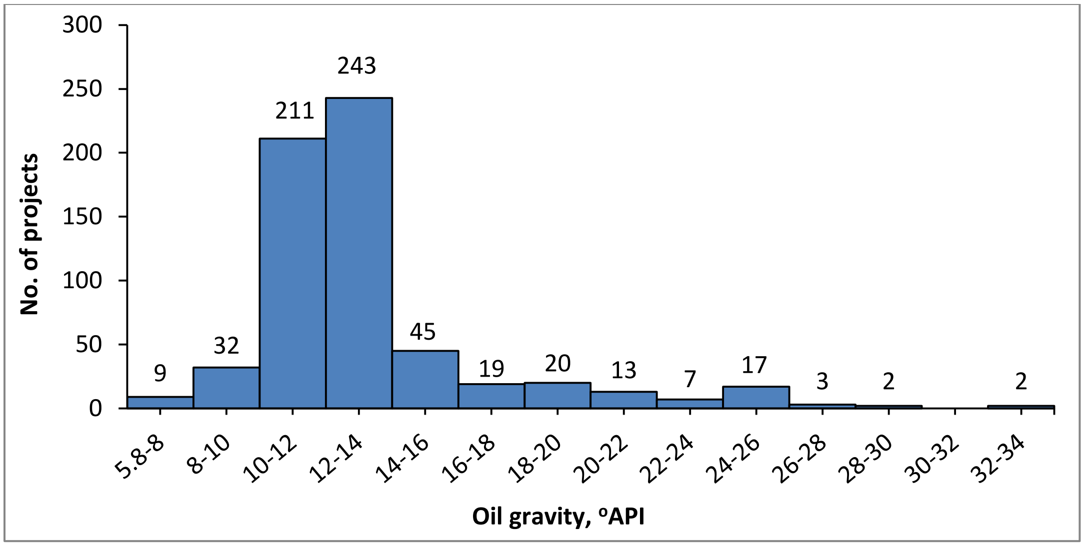

Figure 5.4. Oil gravity distributions of the dataset

Figure 5.5 illustrates the oil viscosity distribution of the dataset across 598 oil viscosity data points. The distribution is skewed to the right. The most frequent viscosity is in the 1,000 to 5,000 cp range. Approximately 85.4% of the data points fall between 100 and 10,000 cp.

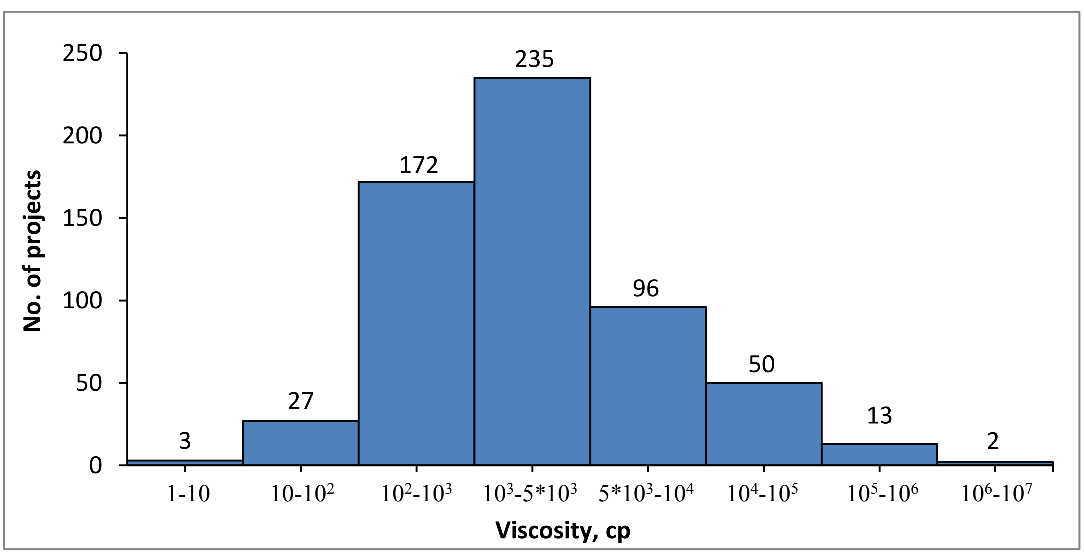

Figure 5.5. Oil viscosity distributions of the dataset

Figure 5.6 shows the reservoir temperature distribution of the dataset, which is characterized by a bell shape (symmetrical or normal). Steam flooding has been implemented in different ranges of reservoir temperatures. The lowest reservoir temperature is between 40 and 50 ^{o}F, and the highest is between 170 and 180^{o}F. The most frequent reservoir temperature is in the 90 to 100 ^{o}F range. Approximately 65% of the temperature data points fall between 80 and 110 ^{o}F.

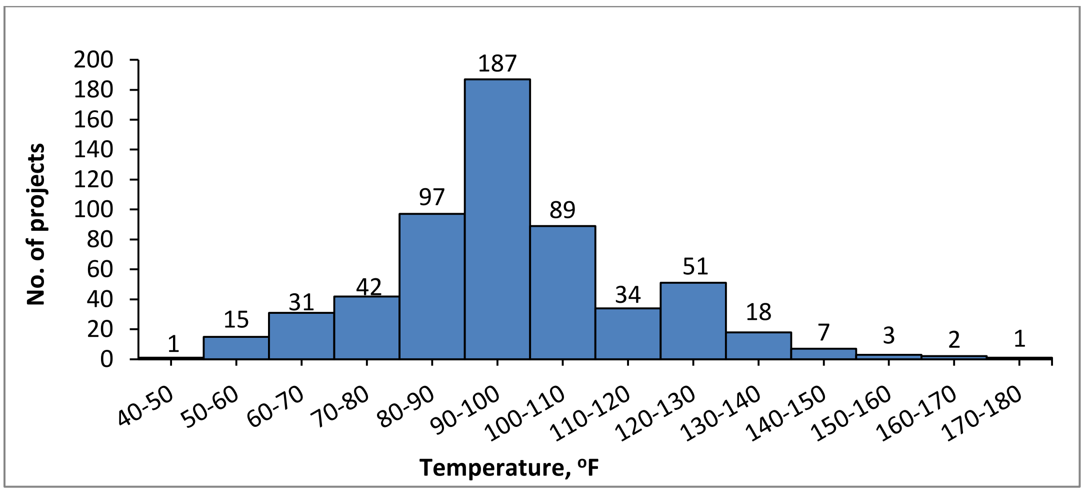

Figure 5.6. Reservoir temperature distributions of the dataset

Figure 5.7 shows the reservoir depth distribution of the dataset across 622 reservoir depth data points. The distribution is skewed to the right. The highest depth frequency is between 1,000 and 1,300 ft. The majority of the data fall between 700 and 1,900 ft, representing 67% of the field projects. There is a tail on the right side of the distribution, and there is only one field project with a depth greater than 5,400 ft.

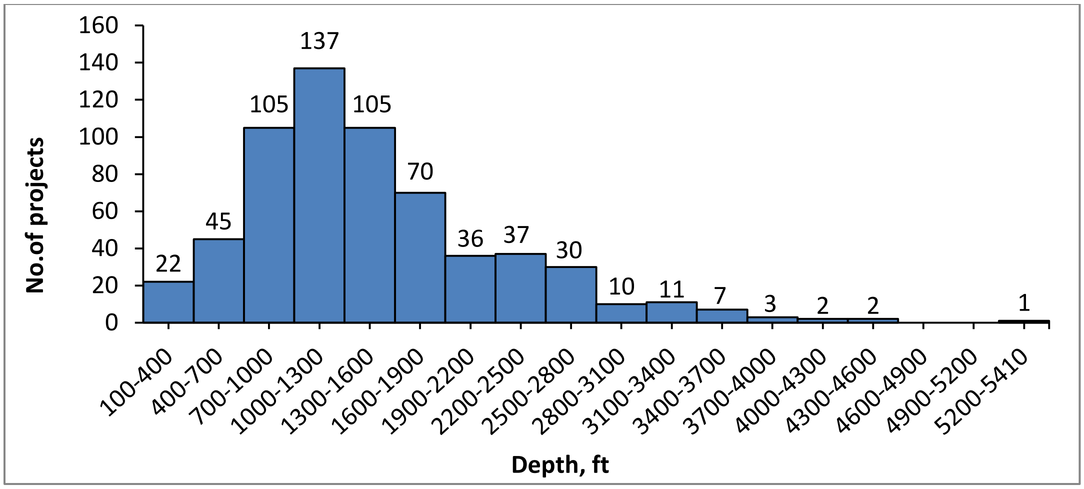

Figure 5.7. Reservoir depth distributions of the dataset

Figure 5.8 shows the oil saturation (start) distribution of the dataset, which is skewed to the right. The highest peak in the distribution is between 50 and 55%. Approximately 88% of the data points fall between 45 and 90%.

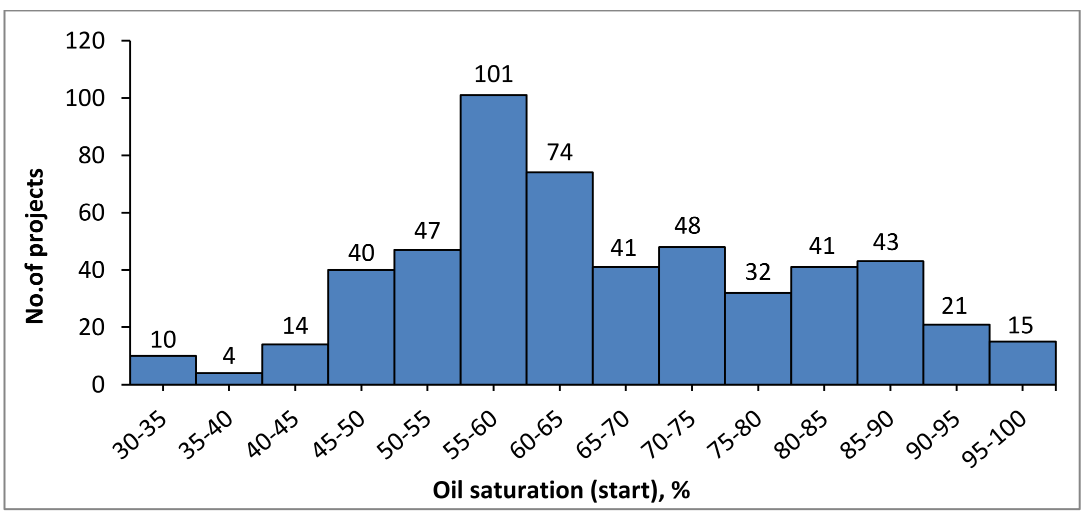

Figure 5.8. Oil saturation (start) distributions of the dataset

Figure 5.9 shows the oil saturation (end) distribution of the dataset across 389 data points ranging from 10 to 89%. The distribution is skewed to the right. The highest oil saturation (end) frequency occurs between 10 and 15%. There is only one data point in the 85 to 89% range.

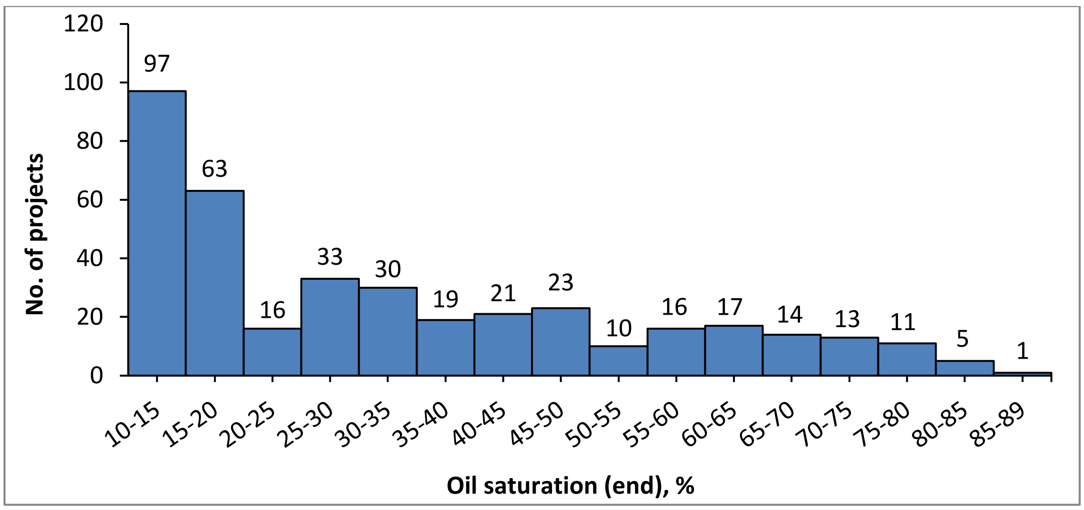

Figure 5.9. Oil saturation (end) distributions of the dataset

5.1.2. Box Plot. Box plots were used not only to detect outliers, as explained previously, but also to display the ranges and summarize the dataset for each variable, as shown in Figure 5.10. Data value ranges were provided for each parameter (minimum and maximum value) after removing outliers. These ranges are illustrated by the distance between the opposite ends of the whiskers. Also, the box plot displays additional information, such as the mean and median of the dataset. A schematic of a box plot was shown previously in Figure. 4.6.

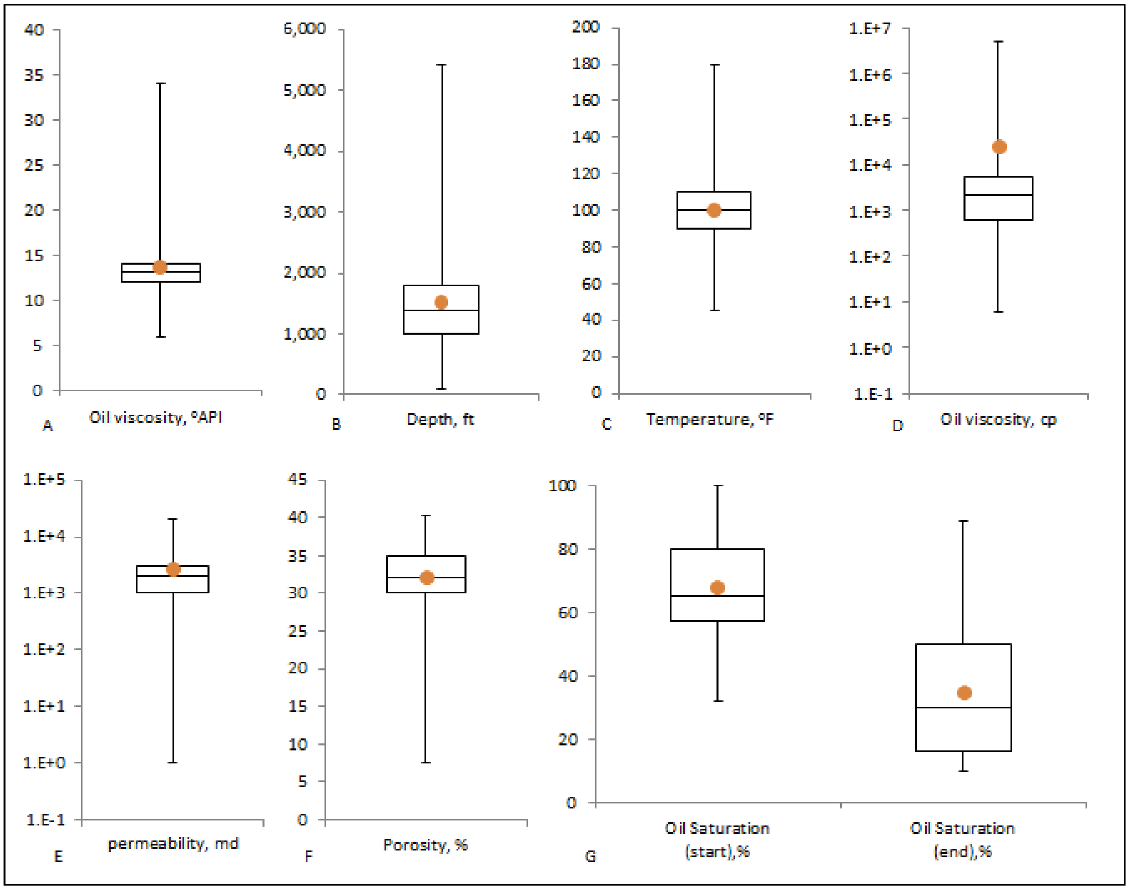

Figure 5.10. (A) Box plot of oil gravity, (B) Reservoir depth, (C) Reservoir temperature, (D) Oil viscosity, (E) Reservoir permeability, (F) Reservoir porosity, (G) Oil saturation start and end

Table 5.1 lists the names and locations of the field projects for each minimum and maximum value of individual screening parameters. Table 5.2 provides the details of the field projects that had the minimum and maximum screening parameter values.

Table 5.1. Names of field projects that have maximum and minimum parameters

Parameters	Names and locations of fields: Min. Value	Names and locations of fields: Max. Value
Porosity	Jesus Maria, USA	Cymric, USA
Permeability	Lacq Superieur, France	Mount Poso, USA
Depth	Coalinga, USA	Gaosheng, China
Gravity, ^{o}API	Oxnard, USA	Shiells Canyon, USA
Oil Viscosity	Shiells Canyon, USA	Athabasca Oil Sands, Canada
Temperature	Midway-Sunset, USA	McKittrick, USA
Oil Saturation(Start)	Midway-Sunset, USA	Pikes Peak, Canada

Table 5.2. Filed projects for each maximum and minimum parameters

Started year	Field name	Country	Formation Type	ø %	K md	D ft	Gravity ^{o}API	μ_o *cp*	T ^{o}F	S_o start	S_{or} end	Project evaluation	Reporting year
1982	Jesus Maria	USA	Fractured Chert-Dolomite	7.5	2.0	3,500.0	9.0	20,000.0	110.0	60.0	45.0	Successful	1986
1985	Cymric	USA	Shale	65.0	15.0	1,400.0	12.0		110.0	65.0	55.0	Successful	2004
1977	Lacq Superieur	France	Limestone	15.0	1.0	2,100.0	22.0	20.0	150.0	45.0		Successful	1988
1971	Mount Poso	USA	Sandstone	33.0	20,000.0	2,000.0	15.0	277.0	110.0	65.0	34.0	Successful	1984
1983	Coalinga	USA	Sandstone	30.0	800.0	100.0	12.5	3,000.0	96.0	70.0	32.0	Successful	1984
1982	Gaosheng	China	Sandstone/Dolomite	25.0	2,200.0	5,410.0	19.0	2,000.0	150.0	65.0		Successful	2008
	Oxnard	USA	Sandstone	36.0	2,500.0	1,800.0	5.8	1,500,000.0	100.0	100.0	66.0	Successful	1984
1973	Shiells Canyon	USA	Sandstone	20.5	140.0	850.0	34.0	6.0	105.0			Promising	1984
1984	Athabasca Oil Sands	Canada	Unconsoli	35.0	10.0	500.0	8.0	5,000,000.0	45.0	85.0	15.0	Successful	2008
1983	Midway-Sunset	USA	Sandstone	30.0	2,000.0	1,500.0	13.0	5,000.0	10.0	60.0	15.0	Successful	2000
1982	McKittrick	USA	Sandstone	37.0	1,500.0	1,100.0	11.3	300.0	180.0	60.0	30.0	Successful	1986
1964	Midway-Sunset	USA	Sandstone	37.0	2,500.0	1,000.0	13.0	1,500.0	110.0	31.8		Successful	1984
1981	Pikes Peak	Canada	Sand.	30.0	6,000.0	1,640.0	12.0	15,000.0	70.0	100.0	80.0	Promising	1984

6. DATA SUMMARY AND CONCLUSIONS

6.1. SUMMARIZING SCREENING DATA

Table 6.1 provides a summary of the updated steam flooding criteria derived from the preceding statistical analysis of the cleaned dataset. This summary includes the screening parameters that have led to the success or failure of steam flooding projects. These parameters include the oil gravity, oil viscosity, reservoir porosity, oil saturation start and end, reservoir permeability, reservoir depth and reservoir temperature. The standard statistics used to describe the criteria are the mean, median, standard deviation, and minimum and maximum values.

Table 6.1. Screening criteria for steam flooding in the dataset

Statistics	Oil gravity ^{o}API	Oil viscosity cp	Temperature ^{o}F	Depth ft	Porosity %	Permeability md	Oil saturation start, %	Oil saturation end, %
Mean	13.7	24,766.2	99.8	1,511.3	32.1	2,529.2	67.7	34.8
Median	13.0	2,100.0	100.0	1,372.5	32.0	2,000.0	65.0	30.0
Standard deviation	3.7	224,773.5	19.6	754.5	4.3	2,457.2	14.9	20.5
Minimum	5.8	6.0	45.0	100.0	7.5	1.0	31.8	10.0
Maximum	34.0	5,000,000.0	180.0	5,410.0	40.3 special case (65.0)	20,000.0	100.0	89.0

The following differences exist between the updated screening criteria and previously published criteria for steam flooding:

- In our dataset, the oil gravity ranges from 5.8 ^{o}API up to 34 ^{o}API. Geffen (1973), Lewin and Associates (1976) and Brashear and Kuuskraa (1978) suggested an oil gravity greater than 10 ^{o}API, while Chu (1985) assigned an oil gravity less than

36 ^{o}API, Dickson et al. (2010) suggested a range of 8-20 ^{o}API and Aladasani and Bai (2010) suggested a range of 8-30 ^{o}API.

- In our dataset, the maximum oil viscosity is 5,000,000 cp, and the minimum is 6.0 cp. Iyoho (1978) reported a viscosity range of 200-1,000 cp, Taber (1997) suggested an oil viscosity less than 100,000 cp and Dickson et al. (2010) suggested 1,000-10,000 cp for successful steam flooding projects. Farouq Ali (1974) suggested oil viscosity less than 1,000 cp, noting that oils with viscosities less than 20 cp usually are not candidates for steam flooding because water flooding is less expensive under these conditions.
- The maximum reservoir temperature in our dataset is 180 ^{o}F, and the minimum is 45 ^{o}F. Other published criteria have reported the reservoir temperature only in relation to the reservoir depth. As a screening criterion, the reservoir depth has priority over the temperature. Aladasani et al. (2010) reported a maximum reservoir temperature of 350 ˚F for steam flooding, but a mistake was made when they converted the temperature from ˚C to ˚F.
- The maximum and minimum reservoir depths are 5,410 ft and 100 ft, respectively, in our dataset. In designing steam flooding projects, the reservoir depth is a significant parameter. Shallow reservoirs are preferable because heat losses in the wellbore are minimal (Donaldson et al., 1989). Chu (1985) assigned a minimum depth of 400 ft., while an upper limit for depth of less than 5,000 ft has been suggested by Lewin and Associates (1976), Brashear and Kuuskraa (1978) and Taber (1997). Aladasani and Bai (2010) suggested an upper limit for depth of 9,000 ft.

- In our dataset, steam flooding had been applied in reservoirs with porosities ranging from 7.5 to 40.3%. The porosity data for six projects (Figs. 10 and 11) were significantly different than the porosity data from other fields. These six shale and tropolitic fields had high porosities ranging from 58 to 65%, with low permeabilities (Table 4). These ranges are special cases. Farouq Ali (1974) and Iyoho (1978) reported that the formation porosity should be equal to or greater than 30%. Chu (1985) suggested porosity greater than 20%.
- The maximum and minimum formation permeabilities are 20,000 md and 1.0 md, respectively, in our dataset. For steam flooding projects, to allow steam injection at adequate rates and to control the speed of the oil flow into the wellbore, the permeability must be suitably high (Donaldson et al., 1989). Farouq Ali (1974) suggested a formation permeability of at least 1,000 md, Iyoho (1978) suggested that this value should be greater than 1,000 md, Taber (1997) suggested a reservoir permeability greater than 200 md and Dickson et al. (2010) reported that this value should be greater than 250 md for successful steam flooding projects.
- The minimum oil saturation (start) for steam flooding projects is 31.8% in our dataset. Lewin and Associates (1976) and Iyoho (1978) suggested that the oil saturation should be greater than 50%, while Chu (1985), Taber (1997) and Dickson et al. (2010) suggested that it be greater than 40%.
- Steam projects were applied mostly in sandstone and unconsolidated sand formations. Steam flooding has not been popular in carbonate formations. If only

the formation type were considered, the applicability of steam flooding in sandstone formations would increase by approximately 84%.

6.2. CONCLUSIONS

- This work described the procedures for cleaning a dataset for EOR projects.
- After data cleaning, the distribution of each parameter for steam flooding projects was presented graphically using histograms and box plots with statistical values.
- New steam flooding screening guidelines were presented and compared with previously reported criteria, and their differences were explained.
- The steam flooding screening criteria can be summarized as follows: oil gravity $<34\ ^{o}$API; oil viscosity $<5x10^{6}$ cp; temperature $<180\ ^{o}$F; porosity >7.5%; permeability >1.0 md; start oil saturation >31.8%; formation-type sandstone, unconsolidated sand and carbonate.
- Specific considerations for steam flooding were presented.

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