geosciences

Review

Enhanced Oil Recovery Using CO_2 in Alaska

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Abstract: Alaska holds more than 68 billion barrels of proved oil reserves and more than 36.7 trillion cubic feet of proved natural gas reserves with some special conditions such as proximity to permafrost, making Alaskan petroleum reserves unique. The low temperature in shallow reservoirs prohibited hydrocarbons' ideal maturation, thereby generating several heavy and viscous oil accumulations in this state. This also limits the enhanced oil recovery (EOR) options, leaving the thermal methods off the table to avoid permafrost thawing, which can cause wellbore collapse. Several solutions have been attempted for improving oil production from heavy and viscous oil in Alaska; however, they have not yielded the desired recovery, and ultimate recovery factors are still less than the global average. One solution identified as a better alternative is using CO_2 as an injecting fluid, alternated by water or mixed with other injectants. This paper provides a comprehensive overview of all studies on using CO_2 for enhanced oil recovery purposes in Alaska and highlights common and unique challenges this approach may face. The suitability of CO_2-EOR methods in the Alaskan oil pools is examined, and a ranking of the oil pools with publicly available data is provided.

Keywords: CO_2; carbon dioxide; enhanced oil recovery; Alaska; heavy oil; viscous oil; North Slope

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Citation: Dogah, B.; Atashbari, V.; Ahmadi, M.; Sheets, B. Enhanced Oil Recovery Using CO_2 in Alaska. *Geosciences* **2021**, *11*, 98. https://doi.org/10.3390/geosciences11020098

Academic Editors: Jesus Martinez-Frias and Bahman Bohloli

Received: 8 January 2021
Accepted: 8 February 2021
Published: 19 February 2021

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1. Introduction

Alaska has a 68 billion barrel reserve of original oil-in-place, with about 13.7 billion barrels recoverable by primary and secondary recovery methods and 36.7 trillion cubic feet of proved natural gas reserves [1,2]. Scientific assessments estimate an additional 24 billion barrels of oil and 103 trillion cubic feet of technically recoverable gas [3]. In the North Slope and Cook Inlet of Alaska, about 12.54 billion barrels of oil have been produced cumulatively until 2019 [4]. North Slope oil is occasionally characterized as a highly viscous oil with an unfavorable mobility ratio, which presents the challenge of low recovery from conventional waterflooding projects. Prudhoe Bay contains an additional 2.5 billion barrels of tertiary recoverable oil, plus a further 426 million in viscous oil reserves from satellite developments such as Orion, Polaris, and Midnight Sun [4]. Viscous oil recovery has been shown to be between 10% and 20% of OOIP as opposed to 35% to 40% in light oil reservoirs [2,5].

Although horizontal drilling has unlocked production from viscous oil reservoirs, waterflood recoveries are low, which necessitates advanced technology such as thermal, chemical or miscible gas EOR processes. However, these processes have their shortcomings [6]. Thermal methods are not feasible in Alaskan wells due to thick permafrost, high well costs, and large well spacing [7,8]. Chemical EOR techniques involve adding polymer molecules to water to increase water viscosity and reduce water mobility. Polymer flooding has historically been the go-to choice for unfavorable mobility reduction in enhanced oil-recovery techniques due to its simplicity and low operational cost [9,10]. The efficiency of polymer injectivity depends on polymer degradation and retention, impacting its transportation in porous media [11–13]. Hydroxyl ethyl cellulose (HEC) and sodium carboxyl-methyl cellulose are some natural polymers used in the flooding processes. Polyacrylamide (PAM), Hydrolyzed Polyacrylamide (HPAM), xanthan, and biological polysaccharides are the common types of synthetic polymers used in flooding procedures. HPAM has been used in the first-ever polymer flooding pilot program in Alaskan wells and has been shown to significantly delay breakthrough time and increase sweep efficiency [12].

Nanoparticle migration has presented permeability reduction by pore-throat plugging, slight sedimentation of nanoparticles, and accumulation of various sizes of nanoparticles in the pore throat. Polymer-nanoparticles-assisted models have been developed to control nanoparticle migration mobility in reservoirs, allowing permeability in water-swept zones to be improved dramatically [14].

Foam flooding has also been considered as one of the chemical methods to improve oil recovery [15,16]. Foam flooding improves volumetric sweep efficiency for the fluid in the solvent phase by reducing injected gas mobility, which is considered a technique for mobility control. [11]. A field trial in the Prudhoe Bay of Alaska in 1991, where foam was injected, yielded a significant reduction in GOR, translating into an increase in oil production for several weeks. It is worth mentioning that at the time, oil production was constrained by the amount of gas reinjection capability; therefore, oil production was prorated based on the well's GOR. [17].

Other chemical EOR techniques involving using nonionic surfactants such as Zizyphus Spina Christi, anionic surfactant, and SDBS have been experimentally shown to change calcite, dolomite and quartz anhydrite wettability from oil wet to neutral-wet or slightly water-wet [18–20]. In a study on calcite, dolomite and quartz core plugs, oil recovery factors of 66%, 41%, and 93% were observed respectively, which is indicative of surfactant success in enhanced oil recovery techniques [18]. A synergic combination of surfactants and polymer flooding has been studied as a potential for EOR in Alaska with encouraging results [21].

Cyclic CO_2 injection, also known as the huff-n-puff method, has been employed in shale formations due to hydraulic and natural fractures. This unique characteristic provides a large contact area for the injected gas to penetrate and diffuse in the rock matrix. The relatively short payback period of cyclic processes, and the use of a single well injector are some of the advantages of cyclic CO_2 injection compared to other techniques [22,23]. It is important to understand the phenomena and parameters governing injectivity in a CO_2 flooding program. How to vary these parameters for optimum injectivity and modify them in case of an injectivity loss, would determine oil recovery or CO_2 storage capacity [24]. Fluid/rock interactions, transport mechanism, and geomechanical effects can potentially impact CO_2 injectivity within any flooding or geological sequestration program. Understanding the impact of temperature, pressure, and carbon dioxide soaking time on carbon dioxide adsorption gives an idea of a target formation's storage capacity [25]. Laboratory experiments of cyclic CO_2 injection have shown shale oil recoveries of between 33% and 85% depending on the shale core type [22]. Huff-n-puff techniques have been primarily performed in shale formations in Alaska, although oil shale deposits in Alaska has been sparse, mainly in the Kandik province of central Alaska. [26].

For miscible gas EOR, miscibility is usually achieved by mixing lean gas with expensive NGL [2]. In the case of injecting NGL's in the reservoir, large volumes required for enhanced recovery can be both impractical and uneconomic. However, miscible gas injection has been successfully applied as a field experiment in Alaska's North Slope [6], albeit with logistical, technical, and economic limitations.

Furthermore, MMP between the viscous oils and conventional miscible injectants is too high for many viscous oils in the Alaskan North Slope [4]. Significant effort has been directed at CO_2-EOR in Alaska, where CO_2 has been used as a stimulant in a single well gas flooding process [27] or as a conventional viscosity reducing injectant in its pure or enriched form [1]. In the gas flooding process, injected CO_2 displaced produced liquid previously occupying pore spaces. Some degree of mass or component transfer (dissolution of gas in residual oil or evaporation of light-oil component into injected gas phase) between oil and injected gas occurs [28]. The solubility of CO_2 in hydrocarbons cause the reservoir liquids to swell, subsequently decreasing oil viscosity and improving mobility [29]. CO_2 achieves miscibility at a pressure between 1040 psi to 4351 psi, reducing the interfacial tension between oil and water [30]. CO_2-EOR and sequestration studies have been shown to decrease emissions into the atmosphere and have been an attractive option for oil and gas operators in Alaska [31]. Some reasons cited for successful CO_2 flooding and sequestration project are increased oil revenue from CO_2-EOR, the presence of an existing caprock with reliable integrity, data availability, and existing infrastructure [28].

Enhanced Oil Recovery (EOR) techniques, both actively employed in fields or purely experimental, have been studied in Alaska [27,30–32]. However, even with perfect design, several operational constraints limit options in this region. Handling sand production in arctic conditions [32], proximity to permafrost and the technical challenges permafrost poses on applying EOR techniques [33,34], high asphaltene content and low in-situ permeability [35], and finally, low net-to-gross sand ratio were some of the challenges that operators had to overcome in designing EOR programs. This paper reviews the current state of CO_2-EOR projects in Alaska presents the ranking of CO_2 field storage capacity and the potential of enhanced production from Alaskan oil fields.

2. Geology of Alaska

Alaska has been described as a jigsaw puzzle placed together over epochs of time as tectonic plates collide with each other [4]. Alaska is located between the arctic margins and the Cordilleran Orogenic Belt of western North America. The landmass was formed due to deformations involving oceanic plates, strike-slip faults, and subduction zones [36]. Metamorphic rocks, deformed under significant heat and pressure, create much of Alaska's bedrock. Faults spatially separate these older metamorphic rocks, many of which are recently active and responsible for earthquakes and volcanoes can be classified into three groups: Metamorphosed continental margin rocks, metamorphosed marine, and marginal sedimentary rocks, and finally, the variably metamorphosed arc-related volcanic, oceanic, sedimentary and plutonic rocks of south-central and south-east Alaska [4].

Prominent tectonic features such as Subduction zones form along most of the Earth's convergent plate boundaries and are responsible for large scale cycling of crust and fluid into the mantle. Evidence for petroleum generation is widespread in subduction-related basins, i.e., oil and gas seeps, hydrocarbon shows in petroleum exploration wells. Figure 1 shows the tectonically active regions that present evidence of forming favorable structural traps, folding, and faults beneficial for hydrocarbon accumulation. It is imperative to note that while the intensity of present-day tectonic events is abundant in the south of Alaska, most of the hydrocarbon accumulations are in the North Slope.

A synoptic view of Alaska and Western Canada's neotectonics provides evidence of the relative motion between North America, Pacific, and Bering plates, which may be the source for many modern deformations, including basins and rifts, observed in Alaska [38]. Alaska has been prolific with significant mineral and hydrocarbon resources primarily due to its dynamic tectonism. The North American plate houses the Cook Inlet Basin, the Nenana Basin, and the North Slope Basin, which is classified as a major play for hydrocarbons in North America [39].

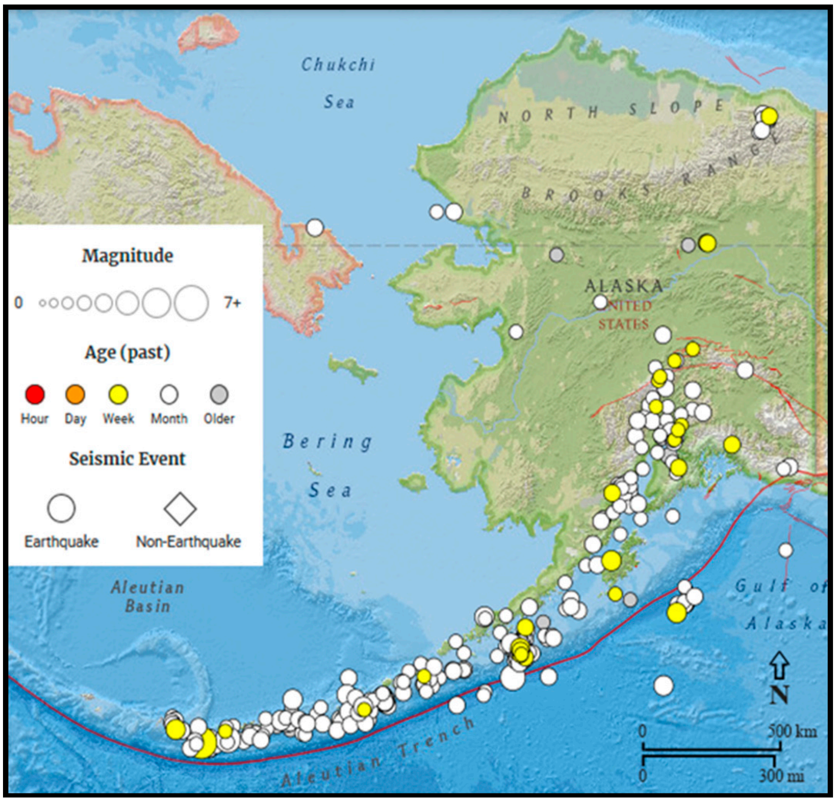

Figure 1. Overall geological setting in Alaska showing active and potentially active fault lines with real-time earthquake activity in a 30-day interval, data from [37]. North Slope is located at the Northern part of Alaska, Cook Inlet at the southern part, and Nenana Basin at the middle, as a part of interior Alaska.

2.1. North Slope Sedimentary Basin

The North Slope sedimentary basin at the north of Alaska consists of two highly deformed Mississippian to earliest Cretaceous continental platform sequences and an overlying Quaternary successor basin sequence [40]. The rock sequence contains the Endicott, Lisburne, Shublik, and Sadlerochit groups [40]. A structural axis known as the east-plunging Barrow arch separates the foreland basin from the passive margin, where most oil and gas accumulations occur [41]. The North Slope aerially ranges from the northern slopes of the Brooks Mountain Range to the Arctic foothills [42]. The Brooks Range consists of rugged, linear mountain ranges at heights of 9900 ft eastward but decreases gradually towards the west [40]. The arctic foothills cover the marshy Arctic coastal plain and move progressively towards the arctic ocean [40]. The Shublik, Kingkak Shale, Pebble Shale Unit, and Torok formations have been shown through preliminary evaluation as the source rock of North Slope and are underlain by the west-trending Colville Basin [36,41].

2.2. Nenana Basin

The basin is located in the interio Alaska, and is filled with Cenozoic strata, including marine fluvial and lacustrine deposits of the Eocene to Miocene Usibelli Group, extending to depths of 25,000 ft to 30,000 ft. Coal intersperses the Usibelli Group, which is mined at the nearby town in Healy [43]. The Nenana Basin primarily contains the Pliocene Nenana Formation and the Miocene Usibelli Group. The Pliocene Nenana group comprises sandstone and claystone with interspersed shale, while the Miocene Usibelli Group comprises sandstone and conglomerate deposited in an alluvial system [43,44].

Gravity modeling [44] of the Nenana Basin area suggests that the most promising petroleum exploration area is a prominent 25 mGal isostatic gravity low north of Nenana. This location corresponds to the deepest part of the sedimentary basin. Low gas saturated sandstone reservoirs have been recently explored within the Minto-Nenana Basin. The Nenana Basin is estimated to hold between 150 billion to 180 billion cubic feet of natural gas [45].

2.3. Cook Inlet Basin

The Cook Inlet Basin, located at the south of Alaska, is famous for being the host of Alaska's first commercial oil discovery in 1957, the Swanson River Field. The basin is characterized by tidal, alluvial, and glacial-fed deposition along the pacific plate between Kenai and Chugach mountains [46,47]. The Cook Inlet is composed mainly of Cenozoic and Tertiary formations, including the Sterling, Beluga, and Tyonek formations housing gas accumulations, and Tyonek, Hemlock, and West Foreland formations housing oil [46]. The Cook Inlet Basin folds into an anticline running from the northeast, dipping at an angle towards the southwest, mainly due to proximity to the plate boundaries [48]. Over a 200 million year period, subduction and associated arc magmatism have been responsible for deformations in this basin [49]. The Cook Inlet Basin consists of more than 18 km of Jurassic to Cenozoic deposits [50]. Nonmarine deposits dominate the Cenozoic Fill and are separated from the underlying Mesozoic units by a regional unconformity. These deposits are related to a spreading center's subduction during the latest Cretaceous-Paleocene time [50,51]. Production from the Cook Inlet Basin peaked at 230,000 barrels per day (bpd) in 1970, fell to 8900 bpd in the 2010 fiscal year, but rebounded to 15,000 bpd in 2016 after tax policy reforms [52]. Table 1 presents a brief overview of the lithology, reservoir and fluid properties of the major oil fields in some sedimentary oil pools of Alaska.

Table 1. Lithology, Rock and Fluid Properties of Alaskan Oil Pools.

Oil Pool/Field		H (ft.)	Reservoir Formation Properties Formation Lithology	∅	k (mD)	S_{wi}	Oil Properties μ_o cp	°API
	Badami Pool	10,500	This pool consists mainly of separate turbidite sandstone reservoirs from the Tertiary-aged Canning Formation. The sandstone reservoir was deposited within mud-dominated submarine fan systems [53].	18.0%	1–400	1.5%–9.6%		30.5
Colville River	Alpine	7000	The reservoir is found in the Jurassic-aged Kingak formation within the Colville Delta area [54]. It consists of shallow marine, very fine to medium-grained, quartz-rich sandstone deposits. The reservoir is underlain by silty shale assigned to the Jurassic Miluveach formation [55].	15%–23%	1–160	12%–30%	0.54	40
	Fiord	6850		11.5%–24%	5–1000	20%–60%	0.97	29
	Nanuq	6150		17.0%	2.5	32%	0.5	40
	Qannik	4000		21.0%	13	35%	2	29
Endicott	Eider	9700	The upper confinement is by the Kayak Shale-Itkilariak formation and in the lower portion by a cretaceous unconformity [56]. Lithostratographic zones 1 comprises shale, coal, and siltstone. Zone 2- medium-grained sandstone. Zone 3- fine-to medium-grained sandstone in stacked point-bar channels [57].	21.0%	134	35.0%	1.56	25
	Endicott Oil	10,000		21.0%	1500	9.0%	1.09	23.5
	Ivishak Oil	10,000		21.6%	600	34.0%	1.56	22

Table 1. *Cont.*

Oil Pool/Field		H (ft.)	Reservoir Formation Properties				Oil Properties	
			Formation Lithology	∅	k (mD)	S_{wi}	μ_o cp	°API
Granite Pt.	Hemlock	10,500	The productive sandstone and conglomerate layers within the pool are found in the lower Tyonek. These layers were deposited in braided streams during the Oligocene to Miocene [58,59].	6.6%	0.5	55.0%	0.53	41
	Middle Kenai Oil Pool	8780		14.0%	10	39.9%	0.31	41
	Hansen	6800		12.0%	17	47.0%	3.5	24
Kuparuk River	Kuparuk Riv Oil	6200	The Kuparuk River Field is the second largest in Alaska, after Prudhoe Bay, located on the Arctic Slope approximately 30 miles west of Prudhoe Bay. The oil field is a sequence of clastic sediments deposited on a shallow marine shelf during the Early Cretaceous time. The Formation is divided into the Lower Member (units A and B) and the Upper Member (units C and D). Units A and C are the leading oil-bearing intervals [60,61].	20.5%	150	35.0%	2.2	23
	Meltwater Oil	5400		20.0%	10	40.0%	0.75	36
	Tabasco Oil	6107		22.0%	5500	21.0%	251	16.5
	Tarn Oil	6747		20.0%	10	40.0%	0.55	37
	Torok Oil	5000		21.5%	46.75	57.5%	2.5	26.5
	West Sak Oil	10,290		30.0%	1007.5	30.0%	42	19
McArthur River	Hemlock Oil	10,227	This field is located offshore Cook Inlet, approximately 64 air miles southwest of Anchorage and 24 air miles northwest of Kenai. The Formation is mainly made of conglomerate sandstone. Three oil-producing formations are located in the Tertiary and one in the Mesozoic. [55,62].	10.5%	53	35.0%	1.19	33.1
	Midkenai G Oil	10,227		18.1%	65	35.0%	1.09	34
	Undefined Oil	10,227		4.9%	6.3	34.0%	1.13	33
	W Foreland Oil	9650		15.7%	102	35.0%	1.497	30.3
Milne Point	Kuparuk River Oil	7000	The reservoir is divided into four informal units (A, B, C, and D in ascending order). Unit A is composed mainly of fine-grained sandstone, Unit B- interlaminated siltstone, and sandstone. Unit C- medium-grained sandstone, with the overlying Unit D consisting of shale [63,64].	21.0%	40	25.0%	3.2	23
	Sag River Oil	8750		17.0%	2	40.0%	0.3	38
	Schrader Blff Oil	4000		29.0%	1500	35.0%	80	14
	Ugnu Undefined Oil	3500		33.0%	2500	20.0%	1753	13.1
Oooguruk	Nuiqsut	6350	The Oooguruk field consists of Neocomian, transgressive sediments deposited within a marine shelf and shoreface environment, overlaying the Lower Cretaceous Unconformity. It mainly comprises bioturbated sandstones, siltstones, and mudstones [65,66].	(2–20)%	3.1	30.0%	4.5	19
	Kuparuk	6050		(13–32)%	50	30.0%	2	23
	Torok	500		19.0%	4	52.0%	3	24

Table 1. *Cont.*

Oil Pool/Field		H (ft.)	Reservoir Formation Properties				Oil Properties	
			Formation Lithology	∅	k (mD)	S_{wi}	μ_o cp	°API
Prudhoe Bay	North Star Oil	11,100	The Prudhoe Bay field encompasses the Sag River, Shublik, and Ivishak formations. Sag River consists of a lower sandstone member and an upper shale member; the Shublik Formation consists of organic-and phosphate-rich sandstone, muddy sandstone, mudstone, silty limestone, and limestone. The principal oil-bearing formation is the Permo-Triassic Ivishak Formation [67]. It consists of sand and conglomerate and lies within the Sadlerochit group. The formation base is made up of clay-stone and shale, which grade upward into interbedded fine-grained sandstone. Overgrowths of silica cement represent the most crucial diagenetic factor limiting porosity across the field [68].	15.0%	366	54.0%	0.14	
	Kuparuk	9000		20.1%	220	29.0%	0.012	
	Aurora Oil	6700		18.0%	44	45.0%	0.72	29.1
	Borealis Oil	6600		18.0%	22	44.0%	2.97	24.1
	Lisburne Oil	8900		10.0%	1	30.0%	0.9	27
	Midnight Sun Oil	8050		21.0%	540	18.0%	1.68	27
	Prudhoe Bay Oil	9245		20.0%	265	40.0%	0.425	32.5
	Niakuk Oil	9200		20.0%	500	28.0%	0.94	25
	Polaris Oil	5000		26.4%	78	54.0%	8	18.2
	Prudhoe Oil	8800		22.0%	265	30.0%	0.81	28
	Pt Mcintyre Oil	8800		22.0%	200	15.0%	0.9	27
	Put River Oil	8100		19.0%	173	46.0%	1.84	26.9
	Raven Oil	9850		20.0%	265	30.0%	0.4	32
	Schrader Bluf Oil	4400		27.6%	220	46.5%	11.2	18.7
	W Beach Oil	8800		11.0%	37	58.0%	1.08	25.7
Trading Bay	G-Ne_Hemlk-Ne Oil	9500	The Trading Bay reservoir is loaded Offshore Cook Inlet in a slightly asymmetrical anticline. The lithology primarily consists of sand conglomerate. The main phase of structural development occurred in the Middle to Late Miocene as theCook Inlet Basin underwent a period of increased transpression [69,70].	14.0%	6.4	37.0%	0.87	36
	Hemlock Oil	4400		15.0%	169	43.0%	0.91	34.5
	Mid Kenai B Oil	4400		24.0%	85	36.0%	8.1	22.7
	Mid Kenai C Oil	4400		20.0%	69	34.0%	4.1	25.7
	Mid Kenai D Oil	4400		16.0%	41	35.0%	1.23	31.5
	Mid Kenai E Oil	4400		17.0%	60	38.0%	0.753	29.3
	Undefined Oil	4400		21.0%	85	40.0%	8.1	23

3. Oil and Gas Production in Alaska and Its Future

The US Congress granted statehood to Alaska 2 years after oil was discovered at the Swanson River of the Cook Inlet Basin in 1957. However, the Prudhoe Bay oil field in the North Slope Basin found in 1967 established Alaska as a world-class oil and gas province. The North Slope alone is estimated to hold 22 billion barrels of oil, with 9.6 billion recoverable, and 124 trillion cubic feet (Tcf) of natural gas [7]. Using advanced drilling technologies and EOR techniques such as miscible gas injection, 13 million barrels of oil have been produced from Prudhoe Bay as of 2020, with potential for further production [52]. Figure 2 presents a snapshot of the production history of some oil pools in Alaska, including the Samson River, Hemlock oil which is still in production [55].

The National Petroleum Reserve of Alaska (NPR-A) holds an estimated 17.6 billion barrels of oil, and the assessment of the Arctic National Wildlife Refuge (ANWR) exhibited an estimate of 7.8 billion barrels of recoverable oil [71,72]. The Alaska Ocean Continental Shelf (OCS) is estimated to hold 19.09 billion barrels of oil and 96.76 Tcf of gas at a 95% probability [71].

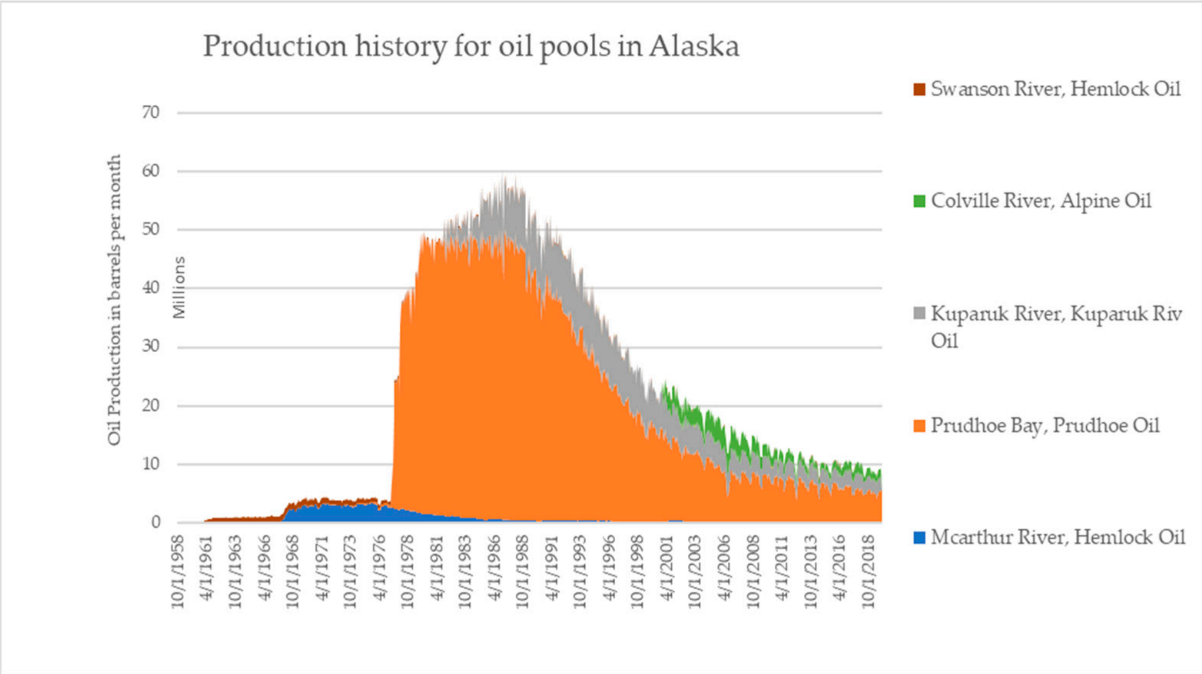

Figure 2. Production history of single pools in the major oil production fields in Alaska. Data was collected from publicly available sources [55].

After 40 years of production, operators in Alaska are pursuing novel ways to develop the remaining reserves, including heavy and viscous resources, remote oil fields, and gas hydrate resources. Oil production has dropped by approximately 75% since hitting a peak of about 2 million barrels per day in 1988. New field discoveries in the Cretaceous Nanushuk and Torok formations offer the potential for increased future production; however, the development of these resources is subject to final investment decisions of at least $11 billion [52]. An attractive option to increase oil recovery in the interim is to exploit the residual, viscous, and heavy oils in Alaska. Improving drilling technology and enhanced oil recovery techniques (EOR) are readily available options to achieve this goal.

3.1. EOR in Alaska

Previous waterflooding attempts in Prudhoe Bay yielded 10–20% of oil production after natural depletion and water flooding mechanisms [4]. During the diagenesis of oil, residual oil is trapped by capillary forces and is surrounded by water or gas occupying the larger pores [72]. In Prudhoe Bay and several projects in the USA and Canada, associated gases produced alongside oil are re-injected into the reservoir to recover part of the oil left behind [6]. Injection of the associated gases with reservoir oil reduces interfacial tension and facilitates the flow of trapped oil.

Table 2 presents an overview of EOR techniques studied and employed in Alaska. Cited articles attempted to address some specific reservoir challenges such as technical restrictions permafrost poses on thermal methods and the structural stability of production facilities, high asphaltene content, as well as sand production handling and control in remote arctic environments.

Table 2. An Overview of EOR Techniques Studied and Employed in Alaska.

EOR Technique	Status	Reference
Polymer flooding	Field experiment	[12] [13,73]
Solvent Based EOR	Field experiment	[74,75] [76]
Low Salinity waterflood	Laboratory studies	[35] [34] [77]
Miscible flooding and viscosity reducing WAG process	Field experiment	[6,75,78,79]
Immiscible Water-Alternating-Gas injection	Simulation studies	[80]
Alkali-Surfactant-Polymer (ASP) flooding	Simulation Studies	[21,81]
CO_2 stimulation (Huff and Puff)	Simulation studies	[1]
Microbial Enhanced Oil Recovery	Laboratory studies	[82–84]
CO_2 flooding in methane gas hydrates	Field experiment	[85,86]

3.2. Polymer Flooding in Alaska

The use of polymer is investigated through an experimental polymer flooding pilot for EOR on heavy oils in ANS [12]. The technique combined polymer flooding, low salinity water flooding, horizontal wells, and occasional injection conformance control treatments as an integrated process. The pilot project acquired scientific knowledge and field performance data to optimize polymer flood design in the Shrader Bluff heavy oil reservoirs. Partially hydrolyzed polyacrylamide (HPAM) polymer was selected, and the initial target viscosity was set at 45 cP [13,73]. The injection pressure was controlled below or slightly higher than fracture pressure to prevent fracture extension, which caused early breakthrough (BT). Step rate and pressure falloff tests indicate that injectivity in the short-term is mostly controlled by fluid mobility deep in the reservoir and not in the vicinity of the wellbore. After nine months of observation from the start of polymer injection, no polymer was observed in the production stream as opposed to a 3-month breakthrough time with waterflood. This result is indicative of polymer significantly delaying breakthrough and increasing sweep efficiency [13,73].

3.3. Solvent-Based EOR in Alaska

Vapor Extraction Process (VAPEX) is considered for the West Sak and Ungu sands of Alaska North Slope. Numerical and experimental studies involving a novel, CT scanner-compatible experimental apparatus for probing vapor enhanced gravity drainage processes suggest a potential of 15–20% additional recovery over the life of the reservoir [74]. This heuristic study showed that although the saturation patterns observed throughout the entire process were uncorrelated, the vapor chamber showed gas segregation toward the top of the pack according to gravity A constant injection rate and a constant bottom hole pressure at the multi-lateral producer well, from an experimental standpoint, yields the longest BT time of the different tested injectants. The numerical modeling shows that 20% of asphaltene is produced, GOR increases after gas BT, and water production is negligible. The VAPEX project will require large volumes of injection solvent from horizontal injectors, affecting the project's economic feasibility. The idea of nano-particle application as a solvent for EOR has been in its feature-reaction catalysis, reducing in-situ oil viscosity and generating emulsion without surfactant [75]. The nano-emulsion flooding can be a useful enhancement for an oil recovery method for a heavy oil reservoir, which is technically sensitive to the thermal recovery method [76].

3.4. Low Salinity Waterflood in Alaska

Coreflooding experiments to evaluate the potential of low salinity brine injection on EOR for ANS observed a consistent trend of reduction in residual oil saturation of up to 20%, and the Amott-Harvey Wettability Index slightly increased with a decrease in injected brine at reservoir temperature [34]. The salinity of the waterflood varied between 22 k total dissolved solids (TDS) and 55 k TDS. An advantage of Low Salinity Waterflooding (LoSal) is the ease with which it can be conducted in harsh operating environments as compared to other chemical EOR processes. LoSal projects do not require importing large volumes of chemicals and don't require difficult surface handling and mixing facilities [35]. Controlling factors in the recovery of a LoSal waterflooding are rock lithology, oil chemistry, and brine salinity. These factors affect the reservoir wetting state and consequently, control the displacement of oil from reservoir rock [77]. LoSal waterflooding has shown significant improvement in the recovery factor by reducing the residual oil saturation (S_{or}) [35,80].

In a single-well chemical tracer test performed in the Ivishak Sandstone, Kuparuk, and Kekiktuk sandstones housing the Endicott oil, waterflood residual saturations were substantially reduced, and LoSal EOR improved OOIP from 6 to 12%. The Ivishak sand vertical test well, L-01 was completed in July 2001 with 4 perforation zones covering an interval of 108 ft. The Kuparuk sand vertical test well, L-122, was completed in 2003 and had a 20 ft thick perforation interval. Finally, the Kekiktuk sand deviated test well, 3-39A, perforated zones 60 ft thick, and produces through 4-1/2 inch production tubing [35].

Similarities between LoSal and alkaline flooding mechanisms such as the generation of surfactants, wettability changes, and reduction in Interfacial Tension (IFT) were also observed [35].

3.5. Viscosity Reducing Water-Alternating-Gas (WAG) EOR Studies in Alaska

In a study on the under-saturated Kuparuk Reservoir, Viscosity-Reducing Water Alternating Gas (VR-WAG) reduced oil viscosity by 45% and improved oil recovery by about 6% OOIP [6]. In that study, heavy components of the produced gas are stripped out and mixed with produced lean gas to manufacture a viscosity-reducing injectant (VRI). The viscosity reducing injectant is injected alternatively with water to control the mobility of the VRI, as well as reducing the viscosity of residual oil [43–45]. Compositional simulation, verified by actual field performance results, showed a viscosity reduction of 90% after injecting the VRI into saturated reservoirs in Alaska. This translated into an improved oil recovery of between 15% and 20% [6]. Nine-spot and modified five-spot patterns with 80 acre well spacing were used in the field experiment performed in December 1982 in the Prudhoe Bay field on Alaska's North Slope. The project consisted of WAG program injecting a slug of more than 10% total pore volume miscible gas (TPV). The injection rate proceeded at 1% TPV per year, followed by water injection, displaces tertiary oil to the producing wells. An incremental-to-waterflood recovery of 5.5% OOIP or 24 million barrels of oil was estimated [78].

3.6. Alkali-Surfactant-Polymer in Alaska

Alkali-surfactant-polymer (ASP) involves injecting alkali into sandstone formations to generate in situ surfactants to reduce interfacial tension and injecting polymer to improve mobility ratio [87,88]. The concentration of alkali, surfactant, and polymer employed depends on the reservoir rock and fluid properties. In an ASP reservoir simulation study on the Western North Slope (WNS) reservoir, oil recovery increased from 3% to 45% after secondary waterflood activities at a bottom hole pressure of 500 psi for 60 years [21]. A conventional 5.

Spot injection pattern was used to evaluate the efficiency of flooding, which showed that ASP flooding in a reservoir with homogeneous permeability, porosity, and low viscosity of the region of 2 cP, oil recovery increased by 6.12% to 51.12% of OOIP. These results were similar to polymer injection (~52.15%) and surfactant injection (~52.123%) [21].

3.7. Microbial EOR Experimental Studies in Alaska

Microbial enhanced oil recovery has not been applied to the ANS but has been experimentally studied to analyze its potential in this region [83]. Microbes are present in many well environments and multiply in the presence of specific nutrients. Proliferation results in the formation of various bioproducts (surfactants, carbon dioxide, acids, polymer, alcohols) that facilitate oil recovery by reducing interfacial tension [84,85]. Carbon dioxide forces the oil out of the formation by dissolving in the oil and reducing the viscosity of the oil [85]. Biopolymers affect the mobility ratio between the displacing water and displaced oil. The experiment showed a 10% to 14% increase in oil recovery from traditional waterflooding to a combined microbial water flooding [83].

4. CO_2 Enhanced Oil Recovery and Sequestration in Alaska

After primary and secondary recovery, the CO_2-EOR process recovers oil by contacting and mobilizing residual oil through improving the volumetric sweep and displacement efficiencies. CO_2 injected into reservoir formations may become miscible or remain immiscible with oil, depending on reservoir pressure, temperature, and oil properties. First contact miscibility, vaporizing gas drive (known as the high-pressure gas drive in some circles), and the condensing gas drive (sometimes called enriched gas drive) are the mechanisms for miscible CO_2-EOR processes. The pressure at which miscibility occurs is known as the minimum miscibility pressure (MMP).

For first-contact miscible processes, CO_2 mixes with reservoir oil in all proportions and remains in one phase. CO_2 is not miscible on the first contact under certain reservoir conditions but develops miscibility at multiple contacts, resulting in improved oil recovery [84]. The vaporizing gas-drive achieves miscibility through in-situ vaporization of the lighter or intermediate components from the reservoir oil [89]. The condensing gas-drive process achieves miscibility by in-situ transfer of CO_2 into the reservoir oil, especially viscous oils [90]. There is a mass or component transfer between CO_2 and oil, which allows the two phases to become completely miscible. A transition zone develops without an interface, with oil in the front and CO_2 in the back [85].

In cases where reservoir composition does not favor CO_2 miscibility, or if the reservoir pressure is below the MMP, the oil will not form a single phase with injected CO_2. In such cases, improved sweep efficiency and additional recovery are facilitated when CO_2 dissolves in the oil, causing oil swelling and viscosity reduction [86]. The miscible CO_2-EOR process is a preferred option because it typically achieves higher recoveries than the immiscible process [91]. Amongst all other EOR methods, CO_2-EOR may be preferred due to the potential for additional hydrocarbon recovery and the ability to sequester CO_2 from an environmental perspective.

A perusal of EOR studies performed across Alaska suggests viscosity-reducing miscible gas injection ranks among the most effective methods of recovering residual oil [2,6]. Viscosity-Reducing Water Alternating Gas (VRWAG) has been shown to reduce oil viscosity by 90% and increase oil recovery by 15% to 20% in the Sadlerochit and Sag River sandstones [6]. In viscous oils of the order of 20 cP, such as light North Slope oils, achieving miscibility is possible by condensing and vaporizing mechanisms. Miscibility is not practical in higher viscosity oils due to high minimum miscibility pressure. Preliminary results from the compositional simulation of Immiscible Water Alternating Gas in the Kuparuk River Unit showed a 1%–3% increase in the original oil-in-place [92]. Higher production rates, improved gas handling, and better reservoir management was also observed [92]. CO_2 flooding becomes an attractive undertaking in Alaska because of its benefits over traditional VRI miscible gas injection processes. The introduction of the 45Q tax credit by the US government, enacted in February 2018, provides an incentive to industrial manufacturers that capture carbon from their operations. They can earn $50 per metric ton (t) of CO_2 stored permanently or $35 if the CO_2 is put to use for EOR [93]. The 45Q also represents an attractive proposition for CO_2-EOR in Alaska.

4.1. CO_2 Immiscible Water-Alternating-Gas Injection in Alaska

Immiscible Water-Alternating-Gas injection (IWAG) increased the efficiency of the waterflooding in the presence of trapped gas [80]. Trapped gas reduced water mobility and forced water to displace oil from smaller pores, thereby lowering residual oil saturation. Compositional simulation studies performed by [92] showed a 1–3% increase in original oil-in-place. Their work highlighted the benefits of tapered WAG schemes keeping the produced gas-oil-ratio (GOR) manageable, with some additional benefits including higher production rates, reduced water handling costs, and better reservoir management in the Kuparuk River Unit of Alaska. Performance of the IAWG process was presented in terms of IWAG patterns. The pattern consists of an IWAG injector and allocated neighboring producers. Results indicate that IWAG is as effective in displacing oil for injected volumes up to 0.4 HCPV as waterflood processes.

4.2. CO_2 Flooding for Methane Gas Hydrates

In 2012 ConocoPhillips, the US Department of Energy, Japan Oil, US Geological Survey, and Metals National Corporation performed a field experiment for CO_2 flooding in the Ignik Sikumi Gas Hydrate resource within the Prudhoe Bay Unit on Alaska's North Slope [94]. The field experiment's objective was to assess the potential of CO_2 exchange for CH_4 in naturally occurring gas hydrate reservoirs. The field experiment was performed as a "huff and puff" operation with a single injection and operation cycle from a single vertical well. It was quickly established that due to the presence of free water in the reservoir, pure CO_2 injection was not a feasible option citing the rapid reduction in the formation permeability due to the formation of secondary CO_2 hydrates [94]. In that study, a 77.5% N_2 and 22.5% CO_2 mixture offered the best potential for gas injection. Observation of recovered gas showed preferential retention of CO_2 and simultaneous production of CH_4. CO_2 was successfully sequestered, although the precise mechanism for the exchange remains unclear. A great deal of uncertainty in the extent and the efficiency of the exchange reaction was introduced because of a complex subsurface environment. Gas hydrate destabilization is self-limiting. A cessation of active energy input, such as depressurization, results in the rapid restabilization of hydrate within the wellbore. This effect confirms the idea that gas hydrate production is not prone to an uncontrollable "chain reaction," hence the poor potential for uncontrolled destabilization by CO_2 flooding [94–96]. Understanding the unique challenges gas hydrate poses to maintaining the reaction instead of controlling it should be introduced into designing new field CO_2 flooding programs to inhibit and mitigate wellbore freeze-up during shut-ins.4.3 Enriched CO_2 flooding in Alaska.

Poor sweep efficiency has been a significant problem of CO_2-EOR recovery processes, including enriched CO_2 flooding programs. Injection strategies, including WAG, has been proven to mitigate this problem [9]. Enriching involves mixing pure CO_2 with natural gas liquids, such as in the heavy oil viscosity-reducing CO_2 flood in West-Central Saskatchewan oil reservoir. These reservoirs were thin and marginal, hence economically unsuitable for thermal methods. An 81 mole % to 19 mole % CO_2 and pentane mixture is substantially more effective in heavy oil viscosity reduction and swelling. Experimental results showed that live-oil viscosity was reduced by 96.5% at 580 psi and 69.8 °F. The enriched mixture recovered 34.2 % of OOIP during WAG cycles than 22.5% OOIP using pure CO_2 [97].

Laboratory experiments and reservoir simulation to investigate the effects of the phase behavior of oil-CO_2 systems on the recovery of Alaska North Slope oils suggest that enriching CO_2 with natural gas liquids in an 85% to 15% ratio had a significant effect on reducing oil viscosity. Pure CO_2 injection reduced oil viscosity from 122 cp to 17 cp, but flooding with enriched CO_2 reduced oil viscosity from 122 cp to 6 cp. The simulation showed that pure CO_2 WAG processes improved viscous oil recovery from the target zone of the order of 44%, while enriched CO_2 WAG improved recovery of up to 50% [2].

4.3. CO_2 Screening for Alaskan Pools

The North Slope of Alaska has produced 18 billion barrels of oil since commercial production commenced, representing 82.5% of the estimated technically recoverable oil from current development fields [7,52]. Technically recoverable natural gas in the North Slope is estimated at 35 trillion cubic feet, with no available gas pipeline for exportation, making miscible gas injection and enriched CO_2 injection a viable option for EOR to produce residual oil. The Cook Inlet region is a partially explored petroleum basin with more than 1.3 billion barrels of oil and 7.8 trillion cubic feet of gas [98]. By the early 2000s, production hovered around 30,000 bpd. It was then believed that more than 90 percent of the region's recoverable oil reserves had already been produced [99]. Knowledge of this makes us believe employing CO_2-EOR techniques is all but economical in the Cook Inlet Basin.

In the absence of simulation and experimental data, economic evaluation, and CO_2 availability, a rapid screening method was developed by [28] to examine the efficacy of CO_2-EOR options available in the oil pools of Alaska. This method was based on oil gravity, reservoir temperature and pressure, minimum miscibility pressure (MMP), residual oil saturation, and analytical methods. These factors were considered to estimate oil recovery at breakthrough (BT), as seen in Table 3. The screening method yields a reasonable evaluation basis as CO2 flooding, based on this screening criteria, was successful in over 51.8% of oil reservoirs studied in Alberta, Canada [28].

Table 3. Screening criteria for application of CO_2-miscible flooding, adapted from [28]. Varying depths, as mentioned for OTA (1978) [100] and Taber et al. (1997a) [90], correspond to API gravity.

Reservoir Parameter	Reported by							
Reservoir Parameter	Geffen (1973) [101]	Lewin et al. (1976) [102]	NPC (1976) [103]	McRee (1977) [104]	Iyoho (1978) [105]	OTA (1978) [100]	Carcoana (1982) [106]	Taber & Martin (1982) s	Taber et al. (1997a) [90]
Depth (ft.)		>3000	>2300	> 2000	>2500	(i) >7200 (ii) >5500 (iii) >2500	<9800	>2000	(i) >4000 (ii) >3300 (iii) >2800 (iv) >2500
Temperature (oF)		NC*	<250				<195	NC*	
Original Pressure (psia)	>1100	>1500					>1200		
Permeability (mD)		NC *		>5	>10		>1	NC *	
Oil Gravity (oAPI)	>30	>30	>27	>35	30–45	(i) <27 (ii) 27–30 (iii) >30	>40	>26	(i) 22–27.9 (ii) 28–31.9 (iii) 32–39.9 (iv) >40
Viscosity (cP)	<3	<12	<10	<5	<10	<12	<2	<15	<10
SOR	>0.25	>0.25		>0.25	>0.25		>0.30	>0.30	>0.2

* NC represents non-critical reservoir parameter in the screening.

At depths of 2000 ft – 3500 ft, temperatures of 87.9 F, and a pressure of 1070 psi, CO_2 will reach a supercritical state and consequently aid in miscibility [90,102]. Depending on the geothermal conditions and hydrodynamic regimes, however, conditions for supercritical CO_2 may change. The upper-temperature limit of 250 °F and lows of 195 °F have also been observed as favorable for miscibility to proceed. [103,106]. For CO_2 flooding to be feasible, reservoir pressure must be greater than the CO_2 critical pressure [101,102]. On the other hand, reservoir pressure of at least 200 psi above the minimum miscibility pressure (MMP) at the start of the CO_2 flooding is recommended for miscibility to be achieved [28]. MMP depends on oil composition, gravity, and reservoir temperature. In the absence of specific information such as composition, MMP is estimated from Table 4 [103]. Another parameter employed in the screening criteria for CO_2 flooding is when the ratio of current reservoir pressure to minimum miscibility pressure (P/MMP) is greater than 0.95 [28]. Finally, oil viscosity is not a direct and necessary screening parameter since it is dependent on oil gravity and reservoir temperature. Light oils of API gravity greater than 48 °API are not conducive for developing multi-contact miscibility. The fraction of residual oil before CO_2 flooding should be greater than 0.25 to be considered economically feasible [28,101,102,104,105]. Reservoir permeability is not a critical screening criterion since oil reservoirs with an appreciable oil production should have adequate CO_2 injectivity. Results from this screening method provide the backdrop of selecting potential Alaskan oil pools for CO_2-EOR projects.

Table 4. Estimates of CO_2-crude Oil Minimum Miscibility Pressure (MMP) Adapted from [103].

Oil Gravity (o API)	MMP (psi)	Temperature (oF)	Minimum Reservoir Pressure Requirement (psi)
<27	4000	120	0
27–30	3000	120–150	200
>30	1200	150–200	350
		200–250	500

A ranking of Alaskan oil pools with the potential for CO_2 sequestration, controlled mainly by field size and fracture gradient, suggests Prudhoe Bay, Kuparuk River, and West Sak as having the largest CO_2 storage capacity [27]. Assuming 100% oil recovery and applying a 20% safety factor on pressures applied during CO_2 storage to avoid over-pressurization, fracturing, and gas leakages in target formations, volumetric calculations estimate the fields mentioned earlier have a static storage capacity of 3 billion metric tons of CO_2. Other assumptions for the volumetric estimation of storage capacity include re-pressurizing the fields to pre-fracturing pressure and applying a 50% storage capacity reduction to account for reservoir heterogeneity [27]. The result is presented in Table 5, indicating Prudhoe Bay having the largest CO_2 storage capacity in Alaska, while Badami oil pool having the lowest CO_2 sequestration capacity in Alaska.

Table 5. CO_2 sequestration Ranking for Alaskan Oil Pools When Pressurized to Original Reservoir Pressures, adapted from [27,55].

Rank	Field	Reservoir Temperature ^oF	Reservoir Pressure, Psi	Potential Mass of CO_2 Storage (Mt)
1	Prudhoe Bay	200	4335	3.99×10^9
2	Kuparuk	160	3135	2.09×10^9
3	Lisburne	183	4490	4.60×10^8
4	Endicott-Keiktuk	218	4870	3.56×10^8
5	West Sak	75	1600	3.04×10^8
6	Schrader Bluff	80	1800	2.05×10^8
7	Orion	87	1950	1.06×10^8
8	Point McIntyre	180	4377	1.46×10^8
9	Milne Point	170	3700	1.23×10^8
10	Colville River	160	3215	1.07×10^8
11	Polaris	100	2250	6.83×10^7
12	Niakuk	187	4446	6.47×10^7
13	NorthStar	254	5305	4.96×10^7
14	Meltwater	140	2370	4.67×10^7
15	Borealis	158	3439	4.05×10^7
16	Aurora	150	3433	3.94×10^7

Table 5. *Cont.*

Rank	Field	Reservoir Temperature °F	Reservoir Pressure, Psi	Potential Mass of CO_2 Storage (Mt)
17	Midnight Sun	160	4045	3.28×10^7
18	Tarn	142	2365	3.20×10^7
19	Endicott-Eider	206	4635	1.08×10^7
20	West Beach	175	4257	6.76×10^6
21	Badami	180	6300	4.86×10^5

The ranking mentioned above gathered Alaskan pool data from open sources to identify reservoirs with the best potential of CO_2 flooding. The selection of screening parameters applied to oil pools in Alaska was based on the summary of screening criteria provided in Table 6 and the reservoir properties of selected oil pools in the public domain [55] presents an overview of the screening criteria of reservoirs with the potential for CO_2-EOR based on six reservoir parameters [28].

Table 6. Summary of CO_2-flooding Screening Criteria Used in This Study Based on Six Reservoir Parameters from [10].

Reservoir Parameter	Shaw & Bachu, 2002 [28]
Depth (ft.)	Not critical. Geothermal conditions and hydrodynamic regimes may mask the influence of depth
Temperature (oF)	195–250
Current Pressure (psia)	200 psi > MMP, greater than Pc of CO2, and (P/MMP) > 0.95
Permeability (mD)	not critical
Oil Gravity (oAPI)	>27 but <48
Viscosity (cP)	not critical
SOR	>0.25

The measured depth of selected Alaskan oil pools was pulled from reservoir well logs, showing minimum depths of 500 ft and maximum depths of 15717 ft. Geothermal conditions, permafrost regions, and hydrodynamic regimes mask the influence of depth on the potential for CO_2 flooding. As a result, the depth was not critical to screening for CO_2 suitability in Alaska. Temperature ranging between 195 °F and 250 °F is ideal for CO_2 flooding, although CO_2 miscibility in oil has been observed at temperatures as low as 87.9 °F [103,106]. The current pressure of pools selected in Alaska must be at least 200 psi greater than MMP and greater than the critical pressure of CO_2, and the ratio of current reservoir pressure to MMP (P/MMP) should be greater than 0.95. Reservoir permeability is not a vital screening criterion because oil reservoirs selected for screening are either currently active or have previously produced oil, indicating adequate CO_2 injectivity. Since extremely light oils such as condensates are not conducive to multi-contact miscibility [28,103], oil gravity greater than 27 °API, but less than 48 °API, is used as a screening parameter. It is worth noting that depth and oil viscosity are not explicitly considered in reservoir screening for CO_2-EOR; hence they are non-critical parameters.

The residual oil saturation for each selected oil pool should be greater than 25% prior to CO_2 flooding for economic feasibility. However, adequate information for the fraction of remaining reservoir oil studied was not available to the authors for screening purposes. The application of these criteria allows for rapid screening and evaluation of Alaskan oil pools, with the potential for CO_2-EOR based on publicly available data. Access to more data would increase the scope of the screening of Alaskan oil pools. Based on previous screening approaches (Table 3) with the addition of P/MMP as a parameter, a new screening of Alaskan oil pools is conducted herein, and the results are presented in Table 7.

Table 7 gives an overview of the potential for CO_2 flooding based on screening criteria obtained from findings in literature. It must be stressed, however that every reservoir has its distinct characteristics and must be studied independently and extensively to make accurate decisions about CO_2 flooding. For instance, this screening criteria suggests that heavy oils in the Kuparuk River, West Sak 1-J project makes it unsuitable for CO_2-EOR, although experimental studies suggest that oil viscosity can be reduced from 122 to 17cp during pure CO_2 flooding, while enriched CO_2 flooding reduced oil viscosity from 122 cp to 6 cp. Simulation studies in this reservoir showed that pure CO_2 WAG processes have the potential of improving viscous oil recovery of the order of 44%, while enriched CO_2 WAG can improve recovery of up to 50% [2]. Another set-back of our screening criteria was the unavailability of residual oil saturation data (Sor). Sor information of the various pools in Alaska was not readily available in the public domain, hence was not included in the screening. Data on the Sor provides a parameter a to assess the economic feasibility of CO_2 flooding in Alaska.

Table 7. CO_2 flooding Screening for Alaskan Oil Pools, Data Gathered from Alaska Oil and Gas Conservation Commission (AOGCC) [55].

Oil Pool	MD (ft.)	T (°F)	P (psi)	k (mD)	API (°API)	μ (cP)	MMP	P/MMP	Suitability for CO_2 Flooding
Badami Pool	10,500	180	6300	1–400	30.5		3000	2.10	possible
Beaver Creek, Beaver Creek Oil	15,717			0.5–75	34.5		1200	0.00	not recommended
Alpine Colville River	7000	160	3537	1–1000	40	0.54	1200	2.95	possible
Fiord Colville River	6850	165	3150	5–1000	29	0.97	3000	1.05	possible
Nanuq Colville River	6150	135	2600	2.5	40	0.5	1200	2.17	possible
Qannik Colville River	4000	89	1850	13	29	2	3000	0.62	not recommended
Eider Endicott	9700	206	1380	134	25	1.56	4000	0.35	not recommended
Endicott Oil	10,000	218	4397	1500	23.5	1.09	4000	1.10	not recommended
Endicott Ivishak Oil Pool	10,000	212	3699	600	22	1.56	4000	0.92	not recommended
Hemlock Undef. Grante Pt.	10,500	185	5500	0.5	41	0.53	1200	4.58	possible
Middle Kenai Oil Pool	8780	174	2620	10	41	0.31	1200	2.18	possible
Hansen	6800	135	2582	17	24	3.5	4000	0.65	not recommended
Kuparuk River, Kuparuk River Oil	6200	160	3106	150	23	2.2	4000	0.78	not recommended
Kuparuk River, Meltwater Oil	5400	140	2300	10	36	0.75	1200	1.92	possible
Kuparuk River, Tabasco Oil	6107	71	1250	5500	16.5	251	4000	0.31	not recommended
Kuparuk River, Tarn Oil	6747	142	2430	10	37	0.55	1200	2.03	possible
Kuparuk River, Torok Oil	5000	140	1995	46.75	26.5	2.5	4000	0.50	not recommended

Table 7. *Cont.*

Oil Pool	MD (ft.)	T (°F)	P (psi)	k (mD)	API (°API)	μ (cP)	MMP	P/MMP	Suitability for CO_2 Flooding
Kuparuk River, West Sak Oil	10,290	75	1600	1007.5	19	42	4000	0.40	not recommended
McArthur River, Hemlock Oil	10,227	180	3600	53	33.1	1.19	1200	3.00	possible
McArthur River, Midkenai G Oil	10,227	174	2525	65	34	1.09	1200	2.10	possible
McArthur River, Undefined Oil	10,227	195	7000	6.3	33	1.13	1200	5.83	possible
McArthur River, W Foreland Oil	9650	183	4000	102	30.3	1.497	3000	1.33	possible
Middle Ground Shoal, Mgs Oil	8000	155	2900	10	36.6	0.71	1200	2.42	possible
Milne Point, Kuparuk River Oil	7000	175	3268	40	23	3.2	4000	0.82	not recommended
Milne Point, Sag River Oil	8750	226	2439	2	38	0.3	1200	2.03	possible
Milne Point, Schrader Bluff Oil	4000	80	1539	1500	14	80	4000	0.38	not recommended
Milne Point, Ugnu Undefine Oil	3500	70	1540	2500	13.1	1753	4000	0.39	not recommended
Orion	4515	94	1800	333.77	17		4000	0.75	not recommended
Oooguruk Nuiqsut	6350	160	2995	3.1	19	4.5	4000	0.63	not recommended
Oooguruk Kuparuk	6050	160	2500	50	23	2	4000	0.56	not recommended
Oooguruk Torok	500	135	2250	4	24	3	4000	0.56	not recommended
North Star, North Star Oil	11,100	254	5305	366		0.14	4000	1.33	not recommended
Northstar, Kuparuk	9000	197	2865	220		0.012	4000	0.72	not recommended
Prudhoe Bay, Aurora Oil	6700	150	3016	44	29.1	0.72	3000	1.01	possible
Prudhoe Bay, Borealis Oil	6600	158	3075	22	24.1	2.97	4000	0.77	not recommended
Prudhoe Bay, Lisburne Oil	8900	183	2990	1	27	0.9	3000	1.00	not recommended
Prudhoe Bay, Midnight Sun Oil	8050	160	3439	540	27	1.68	3000	1.15	not recommended
Prudhoe Bay, N Prudhoe Bay Oil	9245	206	3610	265	32.5	0.425	1200	3.01	possible
Prudhoe Bay, Niakuk Oil	9200	187	4094	500	25	0.94	4000	1.02	not recommended
Prudhoe Bay, Polaris Oil	5000	98	1925	78	18.2	8	4000	0.48	not recommended
Prudhoe Bay, Prudhoe Oil	8800	200	3360	265	28	0.81	3000	1.12	possible

Table 7. *Cont.*

Oil Pool	MD (ft.)	T (°F)	P (psi)	k (mD)	API (°API)	μ (cP)	MMP	P/MMP	Suitability for CO_2 Flooding
Prudhoe Bay, Pt McIntyre Oil	8800	180	3867	200	27	0.9	3000	1.29	not recommended
Prudhoe Bay, Put River Oil	8100	182	4297	173	26.9	1.84	4000	1.07	not recommended
Prudhoe Bay, Raven Oil	9850	207	4210	265	32	0.4	1200	3.51	possible
Prudhoe Bay, Schrader Bluff Oil	4400	87	1763	220	18.7	11.2	4000	0.44	not recommended
Prudhoe Bay, W Beach Oil	8800	175	3609	37	25.7	1.08	4000	0.90	not recommended
Pt Thomson, Thomson Oil	12,500	195			23		4000	0.00	not recommended
Trading Bay, G-Ne/ Hemlk-Ne Oil	9500	165	2100	6.4	36	0.87	1200	1.75	possible
Trading Bay, Hemlock Oil	4400	177	1849	169	34.5	0.91	1200	1.54	possible
Trading Bay, Mid Kenai B Oil	4400	104	985	85	22.7	8.1	4000	0.25	not recommended
Trading Bay, Mid Kenai C Oil	4400	111	1900	69	25.7	4.1	4000	0.48	not recommended
Trading Bay, Mid Kenai D Oil	4400	135	1900	41	31.5	1.23	1200	1.58	possible
Trading Bay, Mid Kenai E Oil	4400	143	1644	60	29.3	0.753	3000	0.55	not recommended
Trading Bay, Undefined Oil	4400	90	1310	85	23	8.1	4000	0.33	not recommended

5. Challenges of CO_2 EOR in Alaska

There are approximately 5 trillion standard cubic feet of CO_2 in the Prudhoe Bay reservoir, which will become available on the North Slope once separated from produced oil at surface facilities [2]. Effluent gases from 107 gravel-pad living quarters and other support facilities, 28 production and gas processing facilities, seawater treatment plants, and power plants are some of the primary sources of CO_2. It becomes crucial to optimally utilize this vast CO_2 resource to improve oil recovery, sequester the CO_2 underground permanently, and to reduce the oil industry's carbon footprint in Alaska [107].

CO_2 injection and sequestration into an oil reservoir have several benefits, as discussed above. However, successful implementation of EOR plans faces several challenges due to the unique circumstances in the arctic region. For example, CO_2 injection in the West Sak Formation with a reservoir temperature of 75 °F due to permafrost and pressure of 1600 psi proceeds at partially supercritical conditions, presenting a series of challenges that need to be addressed [31]. Precipitation of a solid phase occurs when CO_2 mixes with asphaltic oil in low-temperature reservoirs, leading to relative permeability reduction of the liquid phase and a decrease in the injectivity of the well [108,109]. Asphaltene deposition during CO_2 flooding causes formation damage and wellbore plugging and requires expensive treatment and cleanup procedures [110,111].

Another challenge of CO_2-EOR is the poor mobility control of CO_2 due to its very low viscosity (0.0147 cP at 68 °F). In case the gas tends to finger and breakthrough to the producer well earlier than intended, large areas of the reservoir will remain unswept, which is deemed as economic loss. There are several solutions to defer the breakthrough time, which include adding chemicals such as surfactants [112–115] or polymer [9,10,12,116,117] to CO_2, or alternating other chemicals such as water [118–122] or foam [117,123] with CO_2 flooding. Moreover, miscible injectants can also solve the problem of early breakthrough for CO_2 flooding and have been successfully applied in laboratory analysis in Alaska [2], [124,125].

CO_2-EOR introduces significant carbon-dioxide content into the reservoir, which in the presence of water, forms a corrosive compound that poses a substantial risk to the downhole and surface facilities. As an example, CO_2 was identified as the primary corrosion damage mechanism in downhole tubular and topside flowlines of the Salderochit Formation in Alaska's Prudhoe Bay [126]. Corrosion is exacerbated in the presence of relatively high temperature (200 °F–220 °F) and high CO_2 content (12%) in the reservoir gas. Analysis of flowlines, oil transmission pipelines, facility oil piping, process piping, wells, and aboveground storage tanks indicate that internal corrosion was the primary cause of spills in Alaska's North Slope [127]. Corrosion is the most frequent cause of oil spills greater than 10,000 gallons, with external corrosion the dominant cause of flowline spills. The Prudhoe Bay oil spill in 2006 was a five-day leak where 6400 barrels were spilled over 1.9 acres, and was caused by corroding pipelines [128]. To control the issues of corrosion, substantial investments in corrosion-resistant alloys is required for downhole assemblies and surface facilities at the onset of reservoir production [8,129,130]. Alternatively, corrosion inhibitors are designed to protect the facilities against corrosive substances. Improved corrosion inhibitor performance is aimed through the field-wide installation of continuous corrosion inhibitor injection systems at the wellhead of every production well [131–133].

Laboratory analysis, compositional simulation, and economic analysis of CO_2-EOR indicate that this method of improving recovery from an oil reservoir is an attractive and efficient prospect compared to other options for developing viscous oil reservoirs in Alaska [8]. Nonetheless, such projects are set back by large early investments in surface facilities, pipeline, pad, and well assemblies for additional recovery of 7% to 10% OOIP over time, indicating less value than waterflood with sand control [8]. The cost of re-pressurizing recycled gas is also a significant bottleneck to CO_2 flooding in Alaska, as high volumes of CO_2 are required per incremental barrel of oil produced [134].

CO_2 flooding operations in Alaska's viscous oil could be a significant customer for a CO_2 supply to benefit from the EOR and CO_2 sequestration. However, CO_2 availability and supply must be of sufficient quantities for the duration of the project. At full development, CO_2 recycled within the viscous oil developments would require a new, dedicated, corrosion-resistant facility with sufficient capacity to process and re-inject the CO_2 [8,131].

The availability of CO_2 sources, high well costs, large well spacing, and thick permafrost pose challenges to CO_2 flooding for sequestration purposes in Alaska [6,27]. Existing facilities make pipelines the preferred choice for CO_2 transportation in Alaska. There are challenges for transporting CO_2 from the point of capture to a geologically suitable location for sequestration or EOR. These challenges are related to pipeline integrity, flow assurance, capital and operational costs, and health, safety and environmental factors. CO_2 is transported in the supercritical phase, which affects the repressurization distance, the fluid dynamic, and the thermodynamic behavior [135]. Therefore, there will be additional costs involving investment in the number of pumping or compressor stations needed. Numerical and analytical simulation studies suggest that the challenges of CO_2 injection rates, the accessibility of the suitable formations through properly spaced and completed wells, the cost of CO_2 flooding, and constraints like permeability are essential parameters to consider in improving the efficiency of CO_2 flooding and CO_2 sequestration [27].

6. Conclusions

A detailed literature review of the geology and tectonic features of the leading oil and gas basins in Alaska is discussed, which revealed an appreciable number of oil fields such as those located in the Prudhoe Bay Unit had undergone secondary production. As a result, residual oil is trapped by capillary pressure in the pore spaces. Some of the sedimentary oil basins discussed house viscous and heavy oil with a low recovery rate. Several factors affect the recovery of these hard-to-reach hydrocarbon resources. Enhanced oil recovery processes studied experimentally and conducted in Alaskan fields suggest an occasional advantage of miscible gas injection over other EOR techniques in recovering residual oil.

The literature review concluded that miscible oil recovery is achieved by injecting a viscosity reducing agent such as methane or CO_2 at pressures higher than the minimum miscibility pressure (MMP). The water-injected-alternately-to-gas-injection (WAG) technique is employed in the field to increase the reservoir pressure to MMP. CO_2 injection is preferred over other gas injectants for miscible gas EOR because of its lower MMP and broader ranging applicability in greater depth ranges of oil reservoirs. Another benefit of CO_2-EOR is the potential for carbon sequestration in mature oil reservoirs, which presents a viable approach for contributing to the fight against global warming by reducing the amount of greenhouse gases released into the atmosphere.

The feasibility of CO_2-EOR depends on the current oil prices, the availability of cheap sources of CO_2, and existing pipeline systems. Every reservoir required individual examination of EOR options to pick the most efficient and economical alternative. Key parameters are introduced, and unique challenges of the operations in the arctic region are discussed. Based on these parameters, several screening schemes developed to evaluate the suitability of CO_2-EOR for any reservoir were presented. In this paper, a currently published screening scheme is applied to Alaskan oil pools to identify the best potential prospects for CO_2 flooding. The assessment is developed based on previous screening techniques from literature and data availability for Alaskan reservoirs from the public domain.

Author Contributions: B.D. and V.A. developed the CO_2 flooding screening criteria for Alaska's oil pools and drafted the manuscript. M.A. and B.S. reviewed the work and made important suggestions and recommendations for paper revision. All authors have read and agreed to the published version of the manuscript.

Funding: This material is based upon work supported by the Department of Energy under DE-FE0031838, a subaward through the University of North Dakota's Energy and Environmental Research Center.

Data Availability Statement: We thank Alaska Oil and Gas Conservation Commission (AOGCC) for the provision of information to the public which enabled performing this analysis.

Conflicts of Interest: The authors declare no conflict of interest.

Abbreviations

The following abbreviations and symbols are used in this manuscript:

EOR	Enhanced oil recovery
ANWR	Arctic National Wildlife Refuge
NPR-A	National Petroleum Reserve of Alaska
OCS	Alaska Ocean Continental Shelf
MD (ft)	Measured depth
∅	Porosity
k (md)	Permeability
STB	Stock tank barrel
MMP	Minimum miscibility pressure
OOIP	Original oil in place
WAG	Water alternating gas
IWAG	Immiscible Water alternating gas

VRWAG	Viscosity reducing WAG
T	Temperature
P	Current reservoir pressure
μ	Oil viscosity
HCPV	Hydrocarbon pore volume
GOR	Gas oil ratio
HPAM	Hydrolyzed Polyacrylamide
PAM	Polyacrylamide
SOR	Residual Oil Saturation
TPV	Total Pore Volume

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