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CO2-EOR+ in Australia: achieving low-emissions oil and unlocking residual oil resources

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Abstract. The petroleum industry, through the production and consumption of oil and gas, contributes to global greenhouse gas emissions. However, the industry's leadership and experience in underground injection and storage of CO_2, especially through CO_2 enhanced oil recovery (CO2-EOR), which has been proposed as a possible solution to reducing atmospheric CO_2 levels, has not been well acknowledged. Unlike traditional CO2-EOR, which tends to be a net carbon emitter due to the use of predominantly natural CO_2, rather than anthropogenic, CO2-EOR+ focuses on storing a larger volume of CO_2. Thus CO2-EOR+ not only provides a potential solution to dispose of anthropogenic emissions but at the same time reduces reliance on imported oil through increased domestic production. Increased industry interest and energy policy strategies directed at reducing and/or removing emissions from industry processes reflect the growing social and economic impetus to improve operation practices and the petroleum industry's reputation. Residual oil zones (ROZs) below identified oil–water contacts provide an excellent target for the application of CO2-EOR+. They offer a producible residual oil resource accessible through CO2-EOR, as well as a large pore volume for CO_2 storage, with efforts focused on converting ROZs into resources and reserves. Existing fields in the Surat and Cooper-Eromanga Basins are already well placed to utilise anthropogenic CO_2 sources to achieve conventional CO2-EOR metrics. The ROZs in these basins will hopefully allow potential EOR projects to increase the CO_2 volumes stored, per incremental barrel of oil, well past traditional levels (0.2–0.3 tCO_2/bbl), and in doing so, potentially achieve net negative-emission oil.

Keywords: CO_2, CO2-EOR+, Cooper Basin, enhanced oil recovery, Eromanga Basin, net negative emissions, residual oil zone, Surat Basin.

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Introduction

The oil and gas industry is often perceived as a significant contributor to global carbon emissions. However, what is not widely recognised is the industry's long and positive experience with technologies that can reduce or offset emissions from produced hydrocarbons. One example, which is the focus of this paper, is with carbon capture and storage (CCS) and/or carbon dioxide enhanced oil recovery (CO2-EOR). This is where CO_2 is injected into subsurface formations with the goal of extracting stranded oil in the reservoir. In some cases this technology has the potential to actually store more anthropogenic CO_2 than is released in the life-cycle use of the oil produced.

The CO2-EOR operations that aim to store significantly more volumes of CO_2 aim for a dual economic stream of both oil revenues and CO_2 storage offsets and have been designated as CO2-EOR+ (IEA 2015). As discussed in this paper, carefully monitored, documented examples are demonstrating that such developments are viably occurring (e.g. Hornafius and Hornafius 2015). Moreover, CO2-EOR+ projects are able to target and recover residual or overlooked oil resources, for example, from residual oil zones (ROZs) that often appear below appraisal oil–water contacts (OWCs), and remaining oil left behind advancing aquifer fronts in brownfield development (Melzer *et al.* 2006). Some well-known post waterflood CO2-EOR cases are SACROC, the Means San Andreas unit and Wasson Denver unit as presented on an SPE website (SPE 2020).

While Australia is today a major gas exporter, it is a net importer of oil as illustrated in Fig. 1 (Australian Government 2020*a*). Imports of both crude oil and refined oil products have exceeded exports by a fair margin since around 2000, pointing to the lack of oil self-sufficiency in recent years. This is seen in the marked increase in Australian oil consumption since 2002, which has been supplied mainly by a significant increase in imported refined oil products (Fig. 1), amplifying Australia's reliance on foreign oil. Unfortunately for Australia's energy outlook,

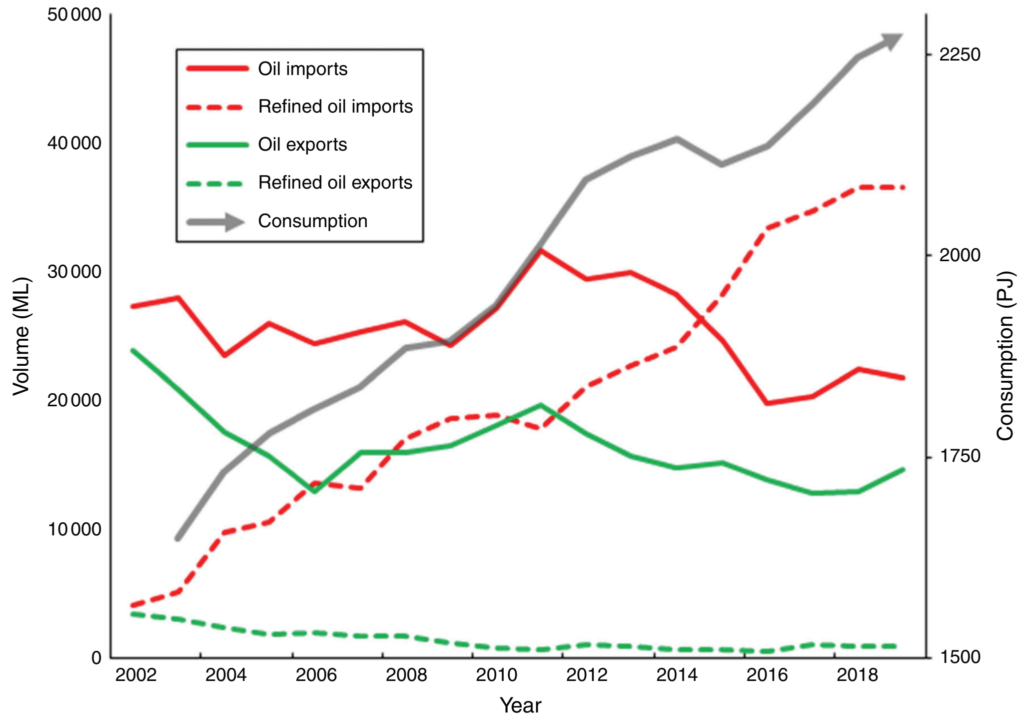


Fig. 1. Australia's oil imports and exports, and growing oil consumption over the past 20 years (data from Australian Government 2020*a*).

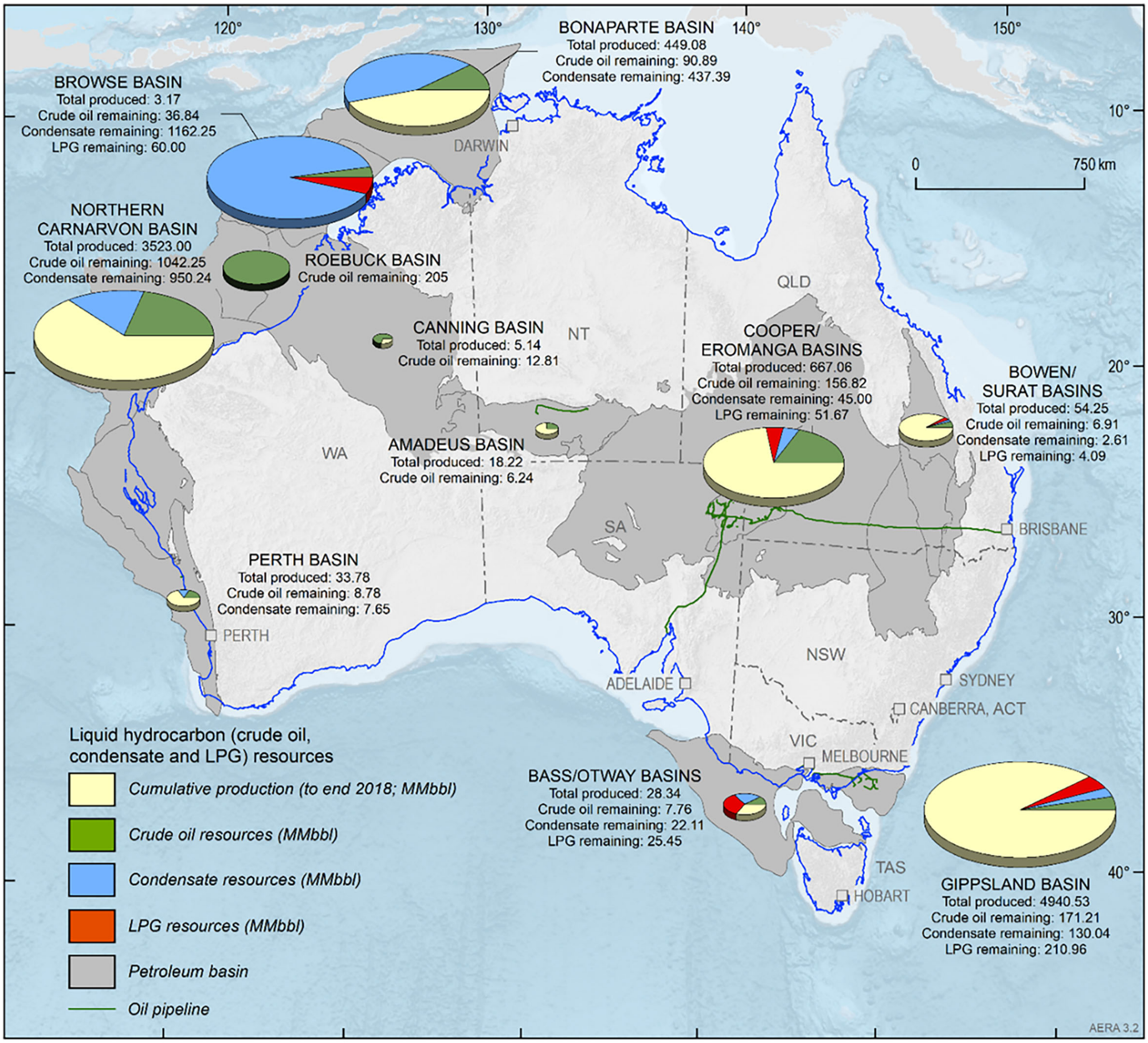
producing oil fields are depleting at a rate which surpasses the development of new resources/fields, leading to declining oil production as a result (Australian Government 2018) (Fig. 2). Production will continue to decline in the foreseeable future without the discovery of new resources or mechanisms to produce from stranded assets (Australian Government 2019).

To date, Australia's experience with CO2-EOR has been very modest, with oil produced largely through primary or secondary (e.g. water flooding) recovery methods. Many of Australia's key hydrocarbon producing basins such as the Gippsland, Cooper, Surat and Carnarvon are trending towards depletion in terms of primary recovery of oil (Fig. 2). This makes these basins prime candidates for the application of CO2-EOR methods as the remaining or residual oil resource can be accessed to extend the life of fields (Tenthorey *et al.* 2021). Although some screening studies have been performed (e.g. Wright *et al.* 1993), suggesting that Australian oils exhibit favourable properties to achieve high displacement efficiencies, there is a lack of substantial CO2-EOR projects. Given the current interest in achieving net zero carbon emissions from a range of industries in Australia, it is timely to consider how CO2-EOR+ might be applied in Australia and what may be the key opportunities and challenges for implementation of this technology.

This paper presents the CO2-EOR+ experience in the international context including several successful international examples of CO2-EOR+, with a discussion of their storage efficiency. It also examines the concept of applying CO2-EOR techniques to ROZs, which have significant CO_2 storage and oil production potential, but are only beginning to be exploited in the USA and the potential for CO2-EOR+ in the Australian context, is discussed. The paper identifies regions in Australia that will likely have the highest potential for near to mid-term application of the technology and the potential barriers to implementing the technology, based largely on international and Australian experiences with innovative ventures in the resource sector. Finally, a preliminary pathway is presented to facilitate the implementation of CO2-EOR+ in Australia. The key conclusion being that while the technical case for CO2-EOR+ is generally understood, managing the development risks and the need for incentives to offset early cash flow loss is going to be critical.

What is CO2-EOR+?

The oil and gas industry's interest in conventional CO2-EOR arose from the inability of conventional waterfloods to achieve high recoveries due to the underlying immiscible behaviour of reservoir brines and oil. Injected CO_2 offers the possibility of enhanced solubility leading to miscibility in some cases that enables injected CO_2 to efficiently mobilise oil components to the producing wells (ARI 2010; NETL 2010). The onshore USA experience has been one where naturally occurring sources of CO_2 have been used to achieve significant production benefits (NETL 2010). Given that the injected CO_2 had to be purchased, the industry chose to explore methods that used relatively small amounts of CO_2 (so-called water-alternating-gas or WAG floods) and realised that significant losses of CO_2 occurred in the reservoir (CO_2 was often left behind in the pore spaces that were previously occupied by oil). Today, companies like Occidental, Chevron and Exxon have accumulated knowledge of CO_2 injection for EOR. The Weyburn project in Canada has demonstrated significant EOR benefits while affording reasonable monitoring to assess the long-term fate of injected CO_2



Sources: Geoscience Australia; Encom GPInfo, a Datamine Australia Pty Ltd
Field outlines and pipeline routes from the GPInfo petroleum database.
Note: Remaining resources is the equivalent of 2P + 2C. LPG = liquefied petroleum gas.

Fig. 2. Australia's produced and remaining crude oil, condensate and LPG resources (Geoscience Australia unpublished).

(Wildgust *et al.* 2013). Weyburn is a successful EOR project, using purchased anthropogenic CO_2, with a strong monitoring component that has shown that significant volumes of CO_2 can be safely left behind in the reservoir. Recent EOR projects, building on sustained research and development efforts from the IEA, US DOE and other organisations promoting enhanced storage of CO_2 with EOR (CO2-EOR+) have sought to maximise both oil production and CO_2 storage components.

Residual vs remaining oil

The term residual oil is commonly used in the oil industry to indicate that a certain saturation percent of in-situ oil will be left behind in the reservoir. It is common to estimate this amount based on small core plugs subject to flooding by multiple pore-volumes of fluid such as brine. It is not uncommon for a laboratory test to subject a core plug to 10 to 20 injected pore-volumes of brine to achieve these oil residual saturations (Dake 2001). The problem with this number, according to some respected engineers such as Dake (2001), is that for all practical purposes, waterflooded reservoirs are nowhere near this level of sweep with typical aquifer influx or active waterflooding. Dake (2001) instead urges engineers to focus on the term remaining oil saturation. The difference between the two terms is quite subtle as even though remaining oil saturations might be 40–60% as opposed to (theoretical) residual oil levels of 20%, the remaining oil can be exceedingly slow moving. The reason we advocate that engineers also use the term remaining oil is that, once CO_2 is utilised, it shows that the potential oil volume able to be accessed can be surprisingly large. Significantly, use of the term remaining oil explains at once why abandonment oil saturations by conventional waterflooding, or aquifer ingress, are nowhere near laboratory residuals. To fully realise the potential for CO2-EOR+ both from the storage and production perspective, it is therefore important to break some bad habits which inaccurately characterise the hydrocarbon system.

Can CO2-EOR+ offset emissions from oil production and consumption?

Net negative CO_2 emissions

While the term 'net negative emissions' is increasingly used to describe efforts and aspirations to reduce carbon emissions to the atmosphere, in this work we use the straightforward definition that the goal of CO2-EOR+ projects is to achieve an overall reduction in the net amount of CO_2 released to the atmosphere as a result of an existing project. If more anthropogenic CO_2 is stored than produced by the full life-cycle emission relating to the production and use of a barrel of oil, then that results in net negative carbon emissions. This definition necessarily includes the CO_2 released through final consumption of any oil produced, that is; it includes the final combustion of the fuel. An immediate consequence of this definition is that the CO_2 must come from sources that would otherwise have vented the CO_2 to the atmosphere. Projects that rely on injection of naturally occurring CO_2 cannot become net negative carbon emitters by definition, as without the project, the natural CO_2 would not have been produced in the first place. We state this up-front because there are other accounting procedures in use that do not consider the full life-cycle but yet make use of the 'net negative' assertion. The technical term for our system is known as 'cradle to grave accounting'.

In order to allow useful metrics to be defined it is helpful to define how much carbon is associated with the various steps of CO2-EOR including downstream transport and consumption of the oil produced. Table 1 provides estimates that have been reported by Godec *et al.* (2017) and Azzolina *et al.* (2016). As will be discussed in the next section, CO2-EOR projects that can achieve a level of oil production and carbon storage that exceeds 0.5 tCO_2/bbl incremental oil are able to claim net negative carbon emission status taking the full life-cycle into account.

CO_2 metrics in EOR projects

In the USA, the oil shocks of the early 1970s prompted industry and government to develop reservoirs that could produce incremental oil through CO_2 injection. Given that most CO_2 in the USA at that time originated from naturally occurring reservoirs, requiring CO_2 to be purchased at the gate (meaning brought into the project, with another gate defined for the project products to leave), the early challenge was to achieve incremental oil production using the smallest amount of CO_2. This gave rise to WAG floods based on small slugs of CO_2, rather than continuous CO_2 injection. CO2-EOR presently accounts for approximately 5–6% of the country's total onshore oil production (~280 000–350 000 bopd) (Eide *et al.* 2019). With the opportunity to access anthropogenic sources of CO_2, and achieve possibly two income streams (from carbon credits in addition to oil sales), attention is now focused more on continuous injection and maximising both the amount of CO_2 stored as well as achieving high incremental oil recoveries (e.g. Hornafius and Hornafius 2015).

More than 50 years of CO2-EOR experience has resulted in 'rule of thumb' estimates regarding the minimum amounts of CO_2 needed to produce a barrel of oil (NETL 2010). Due to the USA oilfield legacy, their metrics are often given in conventional field units (mscf CO_2 injected per stb of oil) as well as international units of (tonne CO_2/barrels of oil). Metrics that were once used to rank conventional EOR projects can also rank CO2-EOR+ projects that seek to store additional CO_2. The IEA (IEA 2015) have defined three classes of CO2-EOR+ that seek to increase the CO_2 storage component while simultaneously providing for the incremental recoveries of the best CO_2 projects – conventional, advanced and maximum storage EOR+ (Table 2). Table 2 summarises field-level metrics for both conventional and CO2-EOR+ projects.

Table 1. Carbon emissions associated with the various steps of CO2-EOR including downstream transport and consumption of the oil produced

Emission stage	Typical CO_2 t/bbl
Transport plant to gate	~0–0.01
Compression/injection/recycle	0.01–0.02
Storage/flaring/transport market	0.03
Distribution and final consumption	0.38
Total	0.42–0.44

International CO2-EOR+ success cases

Despite the recent interest and research focused on CO2-EOR+ activities and potential overall (e.g. Hornafius and Hornafius 2015; IEA 2015), there are few projects in the public literature that can justly be categorised as CO2-EOR+. Part of the ambiguity stems from the fact that relatively few studies differentiate between the total CO_2 injected and the recycled volumes, and determining the 'incremental' portion of the oil produced through EOR is not always straightforward. Whether or not a project qualifies as net negative also depends on the time frame at which the assessment is made. As noted by a modelling study of existing projects, Azzolina *et al.* (2015) show that net CO_2 utilisation per barrel produced is greatest in early years and decreases to a level point over time, as does the associated oil recovery. According to their modelling of 31 CO2-EOR projects, on average the net CO_2 utilisation per barrel of oil levels off at a range centred around 0.5 t CO_2/bbl of oil. This suggests that despite the lack of publicly available data on EOR+ success cases, it is likely that a number of projects do qualify as CO2-EOR+. Below, we discuss several cases that point to the success of CO2-EOR+ in producing additional oil resources while fully offsetting the emissions created by consumption of the produced oil.

Weyburn-Midale project

A mature and highly visible project that has produced significant data and publications is the Weyburn-Midale project in Canada, where CO_2 injection has been underway since the early 2000s using many well patterns and several phases of well and

Table 2. Typical CO2-EOR and CO2-EOR+ project metrics

Project name	Net utilisation		Incremental RF (%)	Net negative?	Comment
	CO_2 t/bbl	Mscf/bbl			
'Average': CO2-EOR	0.3–0.5	6–9	~5–10	No	Typical of many documented CO2-EOR projects
'Good': CO2-EOR	0.15–0.2	3–4	~10–15	No	Best EOR aims to minimise purchased CO_2
Conventional EOR+	0.3	~6	~6–7	No	Per IEA
Advanced EOR+	0.6	~12	~13	Possible	Per IEA
Maximum storage EOR+	0.9	~18	~13	Yes	Per IEA. More emphasis on CO_2 storage. Arguably project transitions to a CCUS project towards end

completion optimisation. The project has had to contend with early CO_2 breakthroughs, asphaltene occurrence, water injection for mobility control and managing large volumes of recycled CO_2. Nevertheless, the project has stored large CO_2 volumes and produced significant oil. Weyburn is clearly a successful EOR project and has achieved impressive CO_2 utilisation numbers for the incremental oil produced per volume/tonne of CO_2 injected (ARI 2010). We present it here as an internationally important example of significant CO_2 storage even though its status as a CO2-EOR+ /net negative-emission project is uncertain. However it has served as an important research project that has progressed knowledge and monitoring technologies in both the EOR and carbon storage spheres.

The Weyburn-Midale project was initiated in 2000 at the Cenovus Energy Weyburn and Apache Canada Midale oil fields. The project uses CO_2 captured from the Dakota Gasification Company's coal gasification plant in North Dakota and transported via CO_2-pipeline some 330 km to the oil fields (Wildgust *et al.* 2013; Jensen 2015; Whittaker 2015). These fields are still producing ~15 000 bopd as a result of CO2-EOR operations (Jensen 2015; IEA 2018) and the total amount of CO_2 stored is expected to be some 30 Mt (IEA 2018) over the life of the project. The research phase of the project came to a conclusion in 2011, but EOR activities continued following the research phase. Determining the overall quantity of CO_2 stored per incremental barrel of oil produced due to EOR activities is somewhat challenging, mainly due to varying published numbers, each representing a snapshot in time. For example, ARI (2010) reported that 2.4 million tons of purchased CO_2 were being stored per year, during a period in which between 10 000 and 15 000 barrels of tertiary oil was being produced per day. Extending the bopd numbers to annual estimates would suggest that 0.44–0.66 t CO_2 were being stored per barrel of oil produced. This would place the Weyburn-Midale project on the cusp of qualifying as a CO2-EOR+ project. However, it should be stated that the accounting metrics and the proportion of recycled CO_2 included in some of the quoted figures are rather nebulous, which means that the storage efficiency may indeed be lower than the aforementioned numbers. For example, Whittaker estimates an overall storage efficiency of just over 0.3 t CO_2/bbl oil produced at 2010. It is therefore not surprising that there are conflicting values for storage efficiency, as the storage efficiency varies over time, with greatest efficiencies usually observed early on in the project (Azzolina *et al.* 2015).

North Michigan reservoirs

The Niagaran Reef complex in North Michigan is possibly the most well-documented CO2-EOR+ project to date. In this area, the Niagaran oil fields are co-located with shallower Antrim shale gas fields, which contain a high proportion of CO_2 gas (5–30%) (Sminchak *et al.* 2020). In fact, the proportion of CO_2 in the produced gas increases with time as more CO_2 desorbs from the organic shale. The CO_2 gas is separated at a gas processing centre located about 20 km from the oil fields, and can therefore be used as an effective and convenient medium to conduct CO2-EOR activities. In some ways, the North Michigan example is similar to the situation in the Cooper Basin, where CO_2 separated from local natural gases may provide the ability to implement tertiary recovery techniques in the future. The EOR operations have been applied to 10 carbonate reef reservoirs from 1996 through to 2017. During that time, 2.1 Mt CO_2 were stored, producing just over 2.2 mmbbl of oil. That equates to a storage efficiency of 0.95 t CO_2 per barrel of oil produced, which places the project solidly in the domain of CO2-EOR+. As the project used anthropogenic CO_2 sourced from a gas processing facility, the overall project can be considered a truly net negative emission project, according to the criteria set forth earlier in this paper. However, as discussed in Sminchak's comprehensive analysis, if the complete life-cycle emissions are taken into account, then the net storage efficiency is much lower. It is important to note that the reservoir types in this North Michigan example allow for gravity stable up-dip CO_2 injection (ARI 2010) which ensures excellent sweep without the need for water injection. This may be one of the key factors that allows such a high proportion of the CO_2 to be stored permanently, making it a factor to pay attention to in other projects.

Wyoming oil fields

The final example of CO2-EOR+ presented here relates to some of the oil fields in Wyoming, especially the Salt Creek Field, which exhibits significant CO_2 storage efficiency (Hornafius and Hornafius 2015). The Salt Creek Field, which was discovered in 1889, is the largest field in Wyoming, having produced 723 mmbbl of oil from an estimated 1680 mmbbl of oil originally in place. In 2019, Wyoming produced 102 mmbbl of crude oil, an increase from 2018 (Hendricks 2009).

A number of the oil fields in Wyoming are currently undergoing CO2-EOR activities to extend the life of the fields, with the CO_2 supplied from Exxon's Shute Creek Gas Plant. In the case of the Salt Creek Field, CO2-EOR activities were initiated in 2004 and continue to the present day (Hendricks 2009). According to the Wyoming Oil & Gas Conservation Commission (http://wogcc.wyo.gov/), a total of 32 Mt of CO_2 have been purchased (and therefore assumed to be stored), producing an added 35 mmbbl of oil. This suggests that more than 0.9 t of CO_2 has been stored for every barrel of oil produced, thereby making the Salt Creek Field a solid example of CO2-EOR+. Another notable example is the Big Sand Draw project, which has purchased 2.2 Mt of CO_2 since 2014, resulting in an extra 2 mmbbl of oil, placing it at a similar storage efficiency as Salt Creek. Hornafius and Hornafius (2015) examined some of the Wyoming fields and showed that the storage efficiency was highest in the early years, consistent with the work of Azzolina *et al.* (2015), and levelled off at a lower efficiency as the projects matured (Fig. 3). Hornafius and Hornafius (2015) also looked at the Beaver Creek field, which stabilised at about 0.43 t CO_2 per bbl oil produced. Although this field does not meet the CO2-EOR+ criteria defined in this paper, it remains an example of efficient CO_2 storage associated with EOR, especially in the earlier years.

Extending CO2-EOR to ROZs

What are ROZs?

The CO2-EOR technology opens the opportunity to exploit a potentially large, as-yet largely untapped oil and CO_2 storage resource – a ROZ. These are portions of a reservoir that cannot be produced through primary or secondary means (Al Eidan *et al.* 2015) due to lack of pressure drive and the fact that the remaining oil is trapped between grains by interstitial forces. In the past, these zones were overlooked as they were not considered to be economic and/or impossible to produce from. However, in recent years there has been increased interest in understanding and producing from these zones, especially in the Permian Basin of West Texas. The most common and well-studied type of ROZs are brownfield cases, which are associated with oil accumulations. In such cases, a zone of residual oil, of variable saturation, exists beneath the main pay zone due to a natural waterflood which displaced oil that originally saturated the zone completely (Melzer *et al.* 2006). In nearly all cases, the origin of these brownfield ROZs is caused by tectonic factors which have changed the hydrodynamic or geological conditions in and around the reservoir (Melzer *et al.* 2006). Greenfield ROZs refer to zones that may contain residual oil, but which are not associated with conventional accumulations. These zones may be associated with paleo migration pathways, or structures that did not seal and contain oil over geological periods (Allison and Melzer 2017).

As shown in Fig. 4, ROZs associated with conventional accumulations do not possess the same oil saturation throughout the zone, but are gradational from higher oil saturations near the top to a central zone of consistent saturation, to a low saturation tail at the base. Melzer (2006) proposed three types of situations that can cause a natural waterflood which leaves behind a ROZ. The first is caused by basin tilt which causes oil to spill from one side of the trapping structure, creating a new OWC above the original contact and at a different angle. This creates a wedge-shaped zone of residual oil beneath the new OWC that may be significant, if the degree of tilt is large enough. The second case

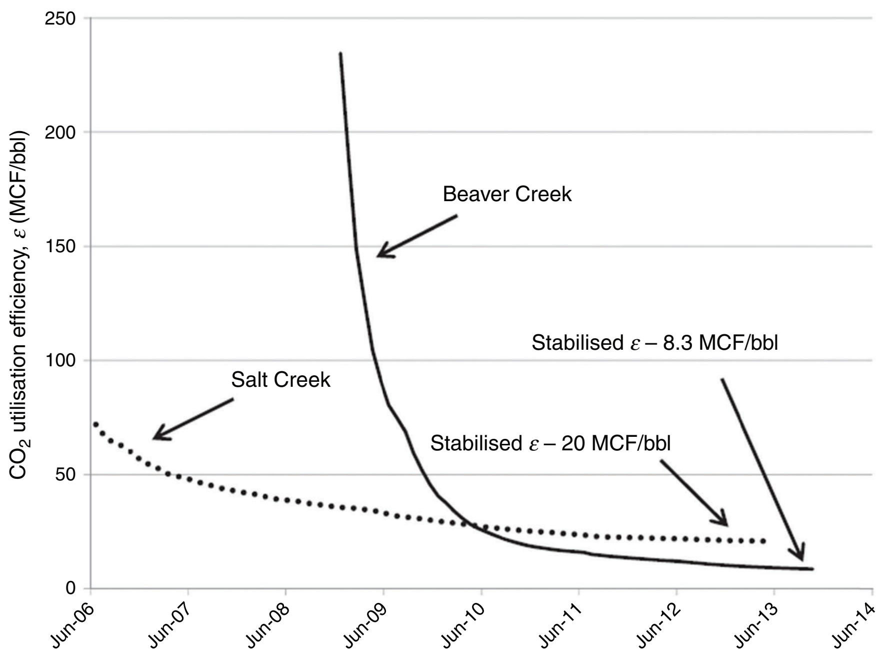


Fig. 3. CO_2 utilisation efficiency at Salt Creek and Beaver Creek EOR projects (Hornafius and Hornafius 2015).

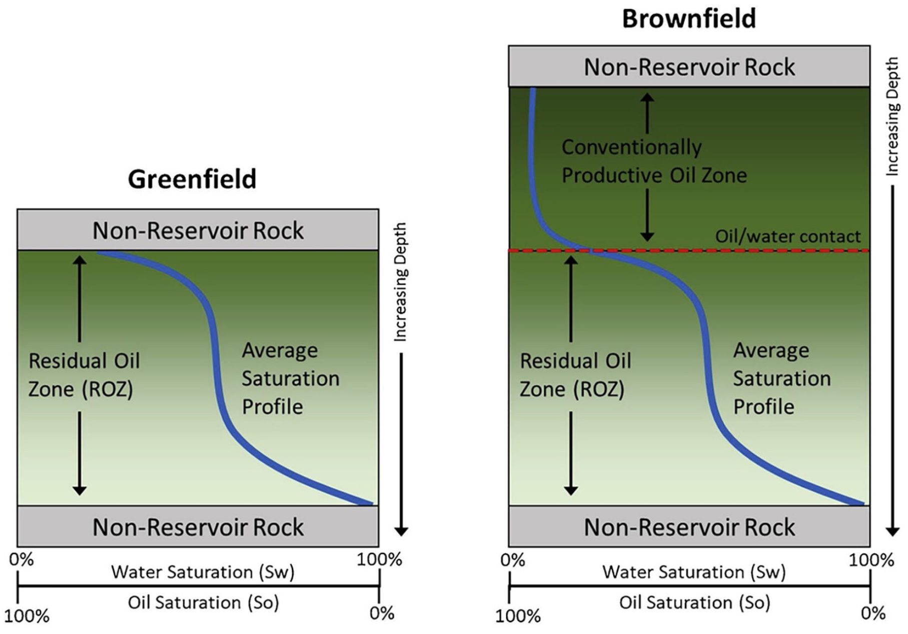


Fig. 4. Residual oil zone schematic (from Sanguinito *et al.* 2020).

involves dynamic seals associated with a conventional accumulation. These may be faults that reactivate and temporarily allow leakage of oil from the structure, or leaky caprock that will only maintain a perfect seal under low buoyancy pressures. Variable leakage from a previously full hydrocarbon structure will leave behind a ROZ below the current OWC. The final case is one associated with distal tectonic activity which can change the hydrodynamic conditions within a field, thereby modifying the angle of the OWC, in much the same way as in the first case. These hydrodynamically driven ROZs are prevalent within the Permian Basin. While Melzer (2006) used the term brownfield to describe changing saturations over long time scales, a similar phenomenon occurs during production time as fluid is withdrawn through wells causing the OWCs to move. As a result there are often low-mobility oil saturations behind water fronts that cause prolonged production at high water cut. These oil saturations contribute to the 'remaining' oil saturation described previously and represent brownfield targets over production time.

International experience with oil production from ROZs

Production from ROZs is concentrated in the Permian Basin in West Texas and southeast New Mexico, USA. Characterisation and exploitation of ROZs in the Permian Basin began in the 1990s and a deeper understanding of the geological development and hydrocarbon potential of ROZs has been gained over the past 10–15 years as more projects come online (Trentham 2018; Trentham and Melzer 2019). The first large-scale brownfield CO2-EOR flooding in ROZs began some 15 years ago (Trentham and Melzer 2019) and, although these and greenfield ROZ plays are still in relatively early stages outside of the Permian Basin, ROZs are now considered producible and economic reservoirs (Trentham 2018). Production of ROZs in this region takes place either through CO2-EOR or through dewatering/depressurisation (DUROZ). The former, although more expensive, can have a considerably higher production rate of ~30% of original oil in place (OOIP) compared to ~7.5% OOIP from dewatering alone, while the latter is more accessible to smaller operators as it does not require CO_2 and related infrastructure (Rassenfoss 2017).

Production from ROZs in the Permian Basin currently largely targets the San Andres Formation, with some 20 or so active projects, and other ROZs have been identified in the basin but are generally not yet sufficiently characterised (Trentham 2011; Kuuskraa *et al.* 2017; Trentham 2018). This includes both exploitation of brownfield ROZs that are located beneath or associated with conventional oil fields, and the first producing greenfield ROZ projects. The San Andres ROZ reaches hundreds of feet in thickness and extends across much of the region with an estimated residual oil saturation comparable to a conventional field following waterflooding (Trentham 2011; Rassenfoss 2017). The technically recoverable oil resource from ROZs in the Permian Basin, using CO2-EOR, is projected to be at least ~12 Gbbl (Koperna *et al.* 2006), based on an assessment of 56 fields with associated transition or residual oil zone plays in the San Andres and Cannon Reed formations, and a calculated oil in place of nearly 31 Gbbl (Koperna *et al.* 2006; Trentham 2011; Roueche and Karacan 2018). The overall resource potential of ROZs in the Permian Basin is likely to be greater, as ROZs in other formations are yet to be characterised and assessed.

Brownfield ROZ projects are most common in this region, where the operators have incorporated the ROZ in their CO2-EOR production of the overlying main pay zones through commingling the main pay zone and ROZ CO_2 floods, and/or by deeper drilling into the underlying ROZ (Trentham 2014; Allison and Melzer 2017; Rassenfoss 2017). KinderMorgan's Goldsmith Landreth San Andres Unit is one such example, where extension of CO2-EOR operations into the ROZ has nearly doubled the estimated recoverable oil from the field

(Trentham 2014; KinderMorgan 2020). In another example, Oxy Permian/Occidental have built on their extensive CO2-EOR operations in the Permian Basin to include development of the transition zone/residual oil zone at the Seminole San Andres Unit and Wasson Fields (Koperna *et al.* 2006; Allison and Melzer 2017; Occidental Petroleum Corporation 2017, 2018). With an oil saturation of 20–40% (Honarpour *et al.* 2010), the estimated additional production from transitional and ROZs associated with their operations in the basin is at least 500 mmbbl (Occidental Petroleum Corporation 2018). Additional to these examples, several other operators are active in developing ROZs in brownfield areas in the basin, also mostly within the San Andres Formation, including, among others, Chevron (Vacuum Field), Fasken (Hanford Field) and XTO/ExxonMobil (Salt Creek, Means Fields) (Allison and Melzer 2017).

Greenfield ROZ projects have also recently started producing oil. The first realised greenfield ROZ project was KinderMorgan's Tall Cotton Field, located to the west of the Seminole and West Seminole Fields in the Permian Basin, where CO2-EOR is used to produce oil from the San Andres ROZ with no associated main pay zone (Allison and Melzer 2017; Rassenfoss 2017; KinderMorgan 2020). The project was initiated in 2014 and by the end of 2018 was producing 3000 bopd from a ~300 foot thick section of the San Andres ROZ with a variable oil saturation of <30% (Allison and Melzer 2017; Trentham and Melzer 2019). Other greenfield operations in the Permian Basin include the CO2-EOR George Allen project, which includes both brownfield and greenfield production accessing the ROZ beneath and beyond the extent of a producing conventional field; and the Platang project, which applies the DUROZ (depressurisation) method of production from the ROZ, using horizontal wells (Trentham and Melzer 2016; Allison and Melzer 2017).

Growing interest in this potentially large hydrocarbon resource has driven a number of studies of onshore and offshore ROZs worldwide (Kuuskraa *et al.* 2017). The Big Horn Basin in Wyoming and Williston Basin, for example, are targets of investigation beyond the Permian Basin in the USA and Canada (Koperna and Kuuskraa 2006; Burton-Kelly *et al.* 2017; Kuuskraa *et al.* 2017). In Europe, Stewart *et al.* (2018) completed the first assessment of the potential application of CO2-EOR to a North Sea ROZ at the Pierce Oil Field. With oil saturation of up to 26%, Stewart *et al.* (2018) predicted that the ROZ could add some 20% to the field's oil reserves as well as store a significant amount of CO_2 (~15 Mt) in a CO2-EOR+ scenario. Also in Europe, Bergmo *et al.* (2018) mapped paleo-ROZs on the Norwegian Continental Shelf (Barents, Norwegian and North Seas) for Statoil, where ROZs of varying thickness, from ~2 to 400 m, were identified in association with some 20 oil fields. Bergmo *et al.* (2018) estimated that the resource of the assessed ROZs could be ~1 GSm^3 (6.29 Gbbl) of oil. In addition, these ROZs could make a significant contribution to CO_2 storage, in total some 330 $MtCO_2$, although the greatest proportion of CO_2 (~1.6 Gt) would be stored in the conventional field zones (Bergmo *et al.* 2018). In the Middle East, Dhote Dhote *et al.* (2018) completed a preliminary study of ROZs in the Kuwait Petroliferous Basin, concluding that there is evidence of extensive ROZ development across the region in a number of formations, although the authors recognise the need for more data in order to define their resource potential.

CO_2 storage in ROZs

In addition to potentially significant oil resources, ROZs offer opportunities for large-scale CO_2 storage that can be accessed through CO2-EOR operations (e.g. Kuuskraa *et al.* 2017; Chen and Pawar 2019). The greater extent of ROZs, compared to oil fields, suggests that in some scenarios there could be a considerably higher capacity for CO_2 storage than in conventional fields, akin to saline aquifer storage, and, as a result, such projects are more likely to achieve neutrality or even net-negative emissions associated with oil production (e.g. Kuuskraa *et al.* 2017; Sanguinito *et al.* 2020). Sanguinito *et al.* (2020) present a methodology for regional scale assessment of the CO_2 storage potential of ROZs that can be applied to ROZs prior to and following oil production, and demonstrate that the storage efficiency in ROZs is comparable to CO_2 storage in saline aquifers. Although ROZs and saline aquifers share many characteristics, such as being extensive, well-sealed, often open systems, ROZs have some advantages over saline aquifers in that they host an economic resource in the form of hydrocarbons, and, for those in brownfield areas, relatively little effort is required to access the resource, e.g. through deeper drilling in existing fields (Kuuskraa *et al.* 2017; Sanguinito *et al.* 2020). Chen and Pawar (2019) modelled that a significant proportion of CO_2 is dissolved in oil in oil-bearing ROZs (and oil fields), compared with saline aquifers, where most CO_2 is present as gas and a relatively small proportion dissolves in water.

Although ROZs may not always have the greater technically or economically accessible capacity for CO_2 storage, they are still expected to make a substantial contribution. In the Norwegian Continental Shelf assessment discussed above (Bergmo *et al.* 2018), for example, it was predicted that while most of the CO_2 would be stored in the fields (~1.6 Gt), a significant proportion (~330 Mt) could be stored in the associated ROZs. One important factor that distinguished CO2-EOR projects from CO_2 storage projects is that CO2-EOR projects have a significant reservoir offtake due to production. Much of the CO_2 storage occurs in the net space created by removing oil from the pore spaces. As a direct consequence of this, the risk of over-pressurisation due to CO_2 injection for EOR projects is reduced, whereas over-pressurisation remains a key risk factor for CO_2 storage projects with no offtake (Hermanrud *et al.* 2013). Only in the later stages of a CO2-EOR+ project, where CO_2 injection may overtake production, would pressure issues become more important. The enhanced solubility of CO_2 in oil, compared to formation water, is another factor limiting over-pressure concerns.

Discussion

The Australian context and why onshore oil fields can be considered for CO2-EOR+

It is predictable that the first Australian candidates in the CO2-EOR+ space will be mature onshore basins that have easy access to CO_2 sources and infrastructure, which will minimise operational costs. Examples of offshore EOR projects are very rare, with the only current example in operation being the Lula field in Brazil (Eide *et al.* 2019). Alvarado and Manrique (2013) point to a number of offshore EOR challenges, such as limited platform area in which to work, the provision of sufficient power supply needed for compression and separation systems, and the costs associated with offshore drilling and production activities. Limited and/or complicated options for the disposal of water containing various solutes and contaminants is also an issue for offshore activity – these can be disposed of within subsurface formations, but may cause follow-on issues relating to pressurisation and geomechanics. Finally, although not likely to be a prime operational cost concern, there are also health and safety concerns using CO_2 in the offshore environment. Therefore, relatively mature onshore basins, close to infrastructure and CO_2 sources, are likely the preferred candidates for the development of CO2-EOR+. For example, existing oil fields in the Cooper Basin are sufficiently large to allow significant quantities of CO_2 to be stored. It is therefore not a surprise that the Cooper and Surat Basins are the two regions where CO2-EOR is currently being investigated. Although CO2-EOR experience in Australia is limited, tertiary recovery techniques have been applied in some fields. Examples include ethane flooding at Tirrawarra in the Cooper Basin and rich gas injection at Corallina in the Bonaparte Basin. Both projects ceased injection, however, once economic opportunities presented themselves for the injected gases.

In the Cooper Basin, Santos is proposing a significant CCS project, which will likely involve some CCUS CO2-EOR component (Winterfield 2018; Santos 2020). The proposed project will access approximately 1.7 Mtpa of CO_2 from the Moomba Gas Plant, which separates CO_2 from the produced natural gas that contains 10–35% CO_2. According to Santos, they plan to draw on the USA experience and aim to increase the production and reserves in the basin. In October 2020, Santos announced a successful injection test of 100 t CO_2 into a depleted gas reservoir at the Strzelecki field as part of the field testing program (Santos 2020). If successful, the basin may also be used for storage of third-party CO_2 that is transported into the basin from external sources. Although public data are not available, a significant work plan has been developed to gauge the EOR potential of both the main pay zone and the ROZ. The workflow has involved fluid sampling and analysis, reservoir simulations, drilling and coring activities and a single well injection test. Based on the reported reservoir and fluid properties, preliminary assessments suggest that Jurassic and Permian reservoir horizons are suitable for CO2-EOR.

The Surat Basin is the focus of a potential CO2-EOR project via Bridgeport Energy, who have conducted detailed EOR studies and simulations on the Moonie Field. The Moonie Field is the largest oil field in the Surat Basin, having produced 24 mmbbl of oil since 1964 (Honari *et al.* 2019). The proposed plan for the Moonie Project is to begin with a pilot project and potentially transition to a full-field oil production scenario if sufficient CO_2 can be acquired. According to Barakat *et al.* (2019), a preliminary simulation suggests that over 3 Mt CO_2 could be stored permanently, resulting in 5–6 mmbbl of incremental oil production. This implies that the storage efficiency is over 500 kg CO_2/bbl of oil produced, meaning the project would qualify as a CO2-EOR+ project. One of the key uncertainties with the Bridgeport Moonie project is the sourcing of a relatively pure stream of CO_2. As of 2019, options to obtain CO_2 from a nearby ethanol plant and possibly from the Millmerran power plant further into the future are being pursued. The Surat Basin region hosts a number of industrial and power generation sources of CO_2, in addition to CO_2 from liquefied natural gas (LNG) processing plants at Gladstone, but purity or transport distance may be an issue.

The outlook for CO2-EOR in ROZs in Australia

Discussion of ROZs in Australia has largely focused, so far, on the resource-rich and mature Cooper-Eromanga hydrocarbon province (Pepicelli 2018; Rendoulis 2018; Winterfield 2018). For example, a 47-m tall paleo-oil column, originating in the underlying Hutton Sandstone, has been recognised beneath the Birkhead Formation in the Eromanga Basin and more oil may have leaked further up section (Boult 1996; Boult *et al.* 1998). Residual oil columns have also been recognised in the Plover and Elang Formations, key hydrocarbon reservoirs in the offshore Bonaparte Basin (Newell 1999).

On one hand, exploration and exploitation of ROZs in Australia is unlikely to flourish until or unless CO2-EOR technology is well established in mature fields. On the other hand, now that production from ROZs has been demonstrated to be both technically and economically viable at large scale in the USA, there is the incentive to implement CO2-EOR in mature/depleted fields. Accessing the ROZ resources, where available, can lead to the production of a larger economic (oil) volume and maximise CO_2 storage. In addition, although not specifically addressing CO_2 storage, DUROZ methods of producing residual oil zones have proved successful and lucrative for small operators in the United States, and could provide a pathway to unlocking ROZ resources that will be ultimately recovered through CO2-EOR. A significant barrier to exploitation of ROZs relates to unknown locations, extents, and the residual oil potential of targeted reservoirs. Therefore, a carefully designed, large-scale exploration program to unlock the ROZ potential in selected basinal sections would be required.

Barriers to CO2-EOR+ in Australia

The uptake of EOR (of any type) in Australia has been slower than a USA benchmark, partly because primary production and water flooding offer 'fast oil', and there has not been a perceived need (yet) for EOR. Australia is predominantly a gas-condensate prone country with limited discovered oil reserves by global comparison, particularly in onshore areas where the implementation of CO_2-EOR is more technically feasible and commercially viable. Most of the onshore oil reserves discovered to date in Australia are located in remote areas, such as central Australia, and these remote locations are characterised by both a lack of nearby sources of CO_2 supply and access, including coverage by existing transport infrastructure. Thus, significant capital costs will be incurred to construct the necessary CO_2-capture, compression, dehydration and transportation network to implement large-scale CO_2-EOR in Australia. Additional commercial and technical barriers to the successful implementation of CO_2-EOR include the requirement to capture and recycle the injected CO_2 as well as issues related to the corrosion of legacy production wells by acidic water containing dissolved CO_2. To transition to large-scale CO2-EOR+, additional costs related to monitoring and verification, as well as site closure activities, must also be included into the economic analysis of potential projects.

Possible enablers for CO_2-EOR and CO_2-EOR+ in Australia

Currently, the only commercial incentive to implement CO_2-EOR in Australia is the increase in incremental oil recovery. The relatively small and geographically dispersed onshore oil resource base and recent contraction in the global oil price may impede the commercial-scale development of CO_2-EOR. However, there are examples of mechanisms that have supported oil and gas development in Australia in the past that could potentially be adapted to encourage development of CO2-EOR in the near to medium term.

The crude oil excise was introduced in 1975 to increase government revenue from oil production associated with the global increase in oil price from 1973. The level of the excise was dependent upon on whether the produced oil was classified as 'old' or 'new'. Oil discovered before 18 September 1975 was classified as old oil, while oil produced from naturally occurring discrete accumulations discovered on or after 18 September 1975 was classified as new. At the time, the level of the excise was set to retain financial incentive for ongoing oil and gas exploration in Australia. An exemption for condensate and LNG from excise was introduced in 1977 due to international oil prices exceeding domestic prices. The exemption applied to gas fields not yet in production with the intent to pioneer the development of the LNG industry in the North West Shelf of Australia. This exemption was later removed in 2008 when the exemption for the LNG industry was deemed to be no longer necessary (https://ministers.treasury.gov.au/ministers/wayne-swan-2007/media-releases/crude-oil-excise-condensate-exemption). In addition to the 1977 exemption for condensate and LNG, the level of oil excise was revised in 1984 to encourage the development of a number of old oil fields that had not been developed because of inadequate returns under the previous oil excise levy. Such fields became eligible for concessional treatment under a new intermediate excise category. The term intermediate oil applied to oil reserves discovered before 18 September but not developed as of 23 October 1984. The rates of excise on old oil and new oil were again reduced on 1 July 2001 to further stimulate the evaluation of fields which were producing old and new oil. These historical policies that were applied to the oil and condensate industries suggest that there are potential tools available to stimulate interest or investment in a new technology application such as CO2-EOR+.

Without the initial technical and commercial success of CO_2-EOR, CO_2-EOR+ is unlikely to be achieved. CO_2-EOR will likely benefit from up-front investment in research and development to demonstrate the effectiveness and economic return of the technology prior to commercial-scale implementation. An analogue example for this technology development might be drawn from the initial research and development into CCS undertaken by the CO2CRC prior to the implementation of the world's largest commercial-scale CCS development on Barrow Island, the Gorgon CO_2 Injection Project (Flett *et al.* 2009). This model may provide an analogue for similar collaborative industry and government research and development into CO_2-EOR and CO_2-EOR+. It should be noted that several enablers and incentives are already in place or in progress in Australia that could support research, development and demonstration, and even commercialisation of CO2-EOR+ in Australia, such as the following: legislation and regulations governing injection and storage of CO_2 in both onshore (states) and offshore (federal) jurisdictions (e.g. *Offshore Petroleum and Greenhouse Gas Storage Act 2006* and state equivalents); CCS included in national strategic plans, such as the Energy Technology Investment Roadmap (Australian Government 2020*b*) and National Hydrogen Roadmap (Bruce *et al.* 2018); and the recommended inclusion of CCUS as a qualifying technology for financing under the Emissions Reduction Fund (King *et al.* 2020) and the Clean Energy Finance Corporation (https://www.cefc.com.au/), which supports commercial-scale projects.

Pathway for development and implementation of CO2-EOR in Australia

Given that experience of CO2-EOR in Australia is very limited, the likelihood of a large CO2-EOR+ project commencing in the near term is considered unlikely. A reasonable expectation is that any path to CO2-EOR+ needs to pass extensive scrutiny in technical, economic and policy arenas. For that reason, we suggest that the likely path forward will be a portfolio reservoir approach based on a sequence of extensive pilot floods into brownfield oil reservoirs. Pilots and international partnerships with established CO2-EOR operators are required to provide local contractors with some accumulated experience and provide policymakers and the public with assurances about the safety and effectiveness of the technology. As a result of their shorter lifetimes, pilot floods allow for monitoring and gaining knowledge and experience based on lesser up-front expenditures. Similarly, a portfolio approach allows smaller candidate reservoirs to be used that alone would not add up to significant CO_2 volumes or significant oil resources, but together have large potential in both respects; additionally, a portfolio approach allows for knowledge and experience from earlier projects to be applied. The economics and policy areas become important because the relationship between injected CO_2 and oil produced generally varies over time. As shown in Fig. 3, the CO_2 storage efficiency is greatest at the early stages of a project, with greater relative proportions of oil being produced later in a project's life cycle. Although discussions regarding policy and legislation are beyond the purview of this study, they will definitely be at the forefront for governing authorities if CO2-EOR+ is considered to be a worthwhile technology for Australia's future.

Nuñez-Lopez *et al.* (2019) makes the point that CO2-EOR is the only commercially established carbon utilisation option that provides large-scale permanent storage for captured CO_2, and CCS is currently the only technology through which industries like steel, cement and petrochemicals can readily be decarbonised. CO2-EOR+ offers a strategy to combine the increased domestic oil production through EOR with carbon emissions mitigation through geological storage of CO_2 under one umbrella. From a financial perspective, CO2-EOR+ is attractive as it can generate additional cash flow streams through the additional produced oil, in addition to any credits or payments to store CO_2.

In the Australian context, some change in mindset across the energy sector will be required for CO2-EOR+ to achieve favourable consideration. In our view, the priority technical areas where action and intervention is required include:

- Supporting the new build of gas pipeline networks and supporting CO_2 distribution centres;
- Recognising and supporting the role of field pilot tests to demonstrate CO_2 injectivity and field response;

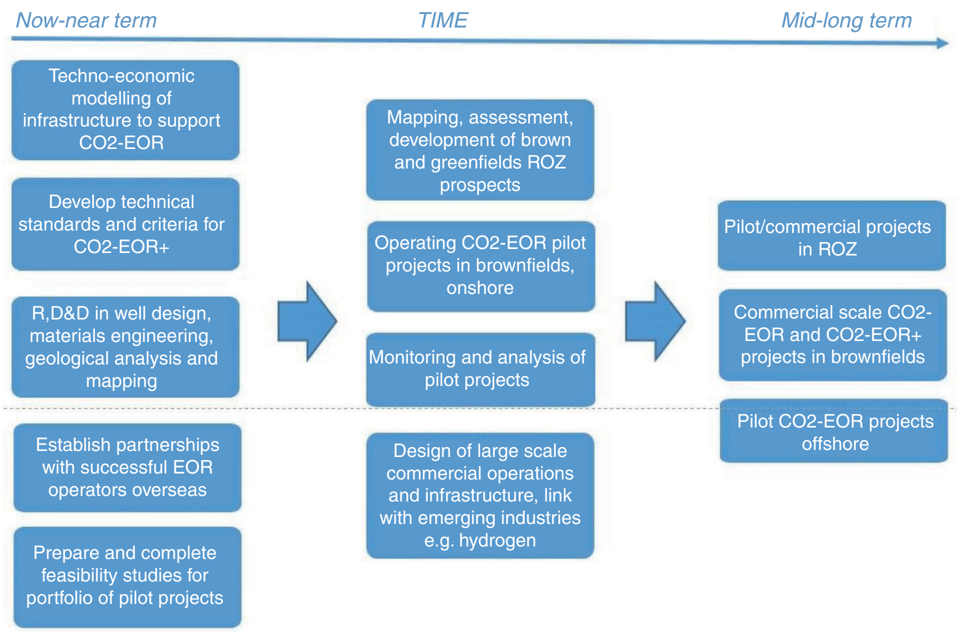


Fig. 5. Possible pathway for the development and implementation of CO2-EOR+ in oil fields and residual oil zones in Australia. R,D&D is research, development and demonstration.

- Promoting brownfield development and engaging with new players to rejuvenate and extend the life of current fields;
- Develop or implement the use of subsurface CO_2 storage certification standards (e.g. DNV GL standards);
- Research, development and deployment in CO2-EOR technology areas (specifically corrosion and flow assurance, monitoring and verification, reservoir characterisation and mapping of ROZs);
- Linking CO2-EOR and EOR+ opportunities with broader CCS opportunities, including the emerging blue or CCS-hydrogen sector and the targeting of ROZs;
- Fostering engagement between the technical community, industry and policy makers to explore the benefits of implementing CO2-EOR+ for domestic oil production and emissions offsets in Australia.

Incorporating these concepts with the barriers to CO2-EOR discussed above, we propose a potential way forward for CO2-EOR in Australia in Fig. 5.

Conclusion

The oil and gas industry is often perceived as being a significant contributor to global carbon emissions; however, the industry also possesses important experience with technologies that can reduce or offset emissions from produced hydrocarbons. CO2-EOR+ offers a strategy to combine the energy security and economic benefits of increased domestic oil production by accessing stranded or residual oil through CO2-EOR, with carbon emissions mitigation through geological storage of CO_2, under one umbrella. Examples of CO2-EOR worldwide demonstrate that offsetting or even achieving net-negative emissions through this production method is not merely aspirational, but realistic.

Although it is in early stages, there is a future for CO2-EOR+ in Australia given suitable geological, technical and regulatory environments and with added financial incentives to promote commercial implementation of the technology. A pathway for CO2-EOR+ in Australia begins by building knowledge and technical capacity in CO2-EOR through R&D and pilot projects in onshore basins and learning from international experience. Encouragingly, several regulatory and financial enablers for CCS are already in place or in development, and two CO2-EOR projects are in early stages in the key onshore oil provinces of the Cooper and Surat Basins. Implementation of CO2-EOR could lead to development of ROZs associated with some oil fields as well as identification and development of primary (greenfield) ROZ resources through CO2-EOR+. Future work focused on identifying, assessing and mapping the extent of the available oil and CO_2 storage resources of brownfield and greenfield ROZs in Australia could add significantly to the nation's natural resources base.

Conflicts of interest

All authors confirm there are no conflicts of interest.

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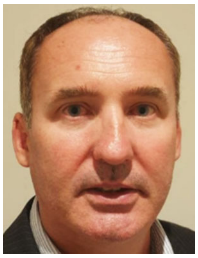

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