Overcoming the Barriers to Commercial CO_2-EOR in Alberta, Canada

by

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EXECUTIVE SUMMARY

Six barriers to commercial CO_2 – EOR (Enhanced Oil Recovery) operations in Alberta are reservoir heterogeneity and oil production, new competing technologies, new oil, carbon capture and storage (CCS), CO_2 supply and unitization. This report focuses on the analysis of the first four barriers (related to the technology of enhanced production of oil) and makes recommendations to overcome them. Since CO_2 supply (related to capture and pipeline economics) and unitization (related to policy development) can be a major barrier for a CO_2 –EOR project, they are also briefly analyzed.

Two simple methodologies are extended and are recommended to evaluate CO_2 – EOR prospects at a high level. The first is a technical assessment which relies on reservoir and piloting properties to choose the best candidates for CO_2-EOR. The second is an economic assessment that uses a simple net back calculation to calculate an affordable price for CO_2 purchased at the field site. The first methodology is used to rate the technical aspects of the commercial (Joffre Viking and Weyburn) CO_2 – EOR operations in Canada and the RCP (Royalty Credit Program) and IETP (Innnovative Energy Technology Program) piloting CO_2 – EOR operations in Alberta (Swan Hills, South Swan Hills, Judy Creek, Redwater, Enchant Arcs, Zama and the Pembina Cardium). The Enchant Arcs is the only oil pool that doesn't satisfy the technical assessment. The second methodology refers to literature examples for government, capital and operating costs to analyze the affordable price of CO_2 for a commercial CO_2 – EOR project.

The decision is not only which are the best CO_2-EOR projects but they also have to compete against other oil and gas projects, as the oil and gas company has to look at the risks of the project, what the financial returns are likely to be and the "processing rate" (i.e. the short term gains which are important to the stock holder). CO_2 – EOR projects are similar to oil sand projects which have large up front expenses before any return is seen. Up to the year 2000 in Canada, CO_2- EOR projects lost out to the hydrocarbon miscible floods (e.g. Swan Hills) due to the ready availability of light hydrocarbon gases and liquids, whereas CO_2 was only available for nearby niche applications (e.g. Joffre Viking). The one exception was Weyburn where a 300 km pipeline had to be built for a CO_2 miscible flood. Weyburn was helped by the rapid price rise in oil, a champion in PanCanadian who were not afraid of the risk, the pioneering use of horizontal wells in a CO_2 flood and a government in Saskatchewan who were willing to change their royalty regime to have the project.

Since that time new technologies have advanced to the stage where tight oil reservoirs (even including source rocks – e.g. the Duvernay) can be profitable to produce on primary by the use of horizontal wells and multistage fracing. The tight oil projects have displaced CO_2 – EOR projects because they have a rapid financial return and low investment costs. As some of these tight pools form haloes (e.g. Swan Hills platform and Pembina Cardium fringes) attached to the conventional reservoirs, unitization may become an important issue as the original unit was only confined to the conventional reservoir. On the back side, because they are low permeability reservoirs, they produce only from 3 to 5% of the original oil in place (OOIP) on primary and should be targets in the future for secondary production. Water flooding may yield poor results in these tight reservoirs due to water blocking which opens them up for gas flooding , possible CO_2.

Other new targets for CO_2-EOR exist. Residual Oil Zones (ROZs) formed by "natures water flood" during uplift and tilting of the Western Canadian Sedimentary may contain huge oil reserves which have not been recognized in the past as the oil will not produce on primary or water flood. Also, recent work on heavy oil suggests that secondary production technology using immiscible gas (preferably CO_2) huff and puff strategy until communication between wells is established (much like the early strategy for the oil sands) is economic in shallow reservoirs down to API 12^o (a gravity much heavier than have ever been considered previously for CO_2-EOR).

Finally, CCS could be considered as an enabler for CO_2 EOR by treating the reservoir as a bank. Roughly, 1/3 of the injected CO_2 remains behind in the reservoir in a CO_2 –EOR project. All the purchased CO_2 is injected into the reservoir (goes into a savings account in the bank) and then is recycled back into the reservoir (a short term CO_2 loan which is paid back). At the end of the project the oil pool is either abandoned (CO_2 stays in savings account in the bank) or blown down and the CO_2 is resold (much of CO_2 is removed from savings account in the bank with only the residual CO_2 remaining). By having a funding program that recognizes the CO_2 storage amounts as they occurs and adjusting the amounts during the process, it would help defray the large capital costs encountered early in the life of a CO_2 EOR project. At the end of the project, a case could be made for the remaining stored CO_2 to be transferred to CO_2 offset credits.

One path forward for overcoming the barriers to commercialization of CO_2 – EOR projects in Alberta is by taking the technologically more attractive CO_2 – EOR pool candidates based on oil pool attributes and piloting results, comparing them against the cost of the CO_2 supply through a netback calculation, and establishing a fund for early recognition of CO_2 storage in CO_2 – EOR commercial projects to address CO_2 price gaps. Other paths forward could be proposed based on utilizing different combinations of the other opportunities previously identified to help overcome the CO_2 – EOR barriers. The most promising path forward could be identified by developing a risk management framework to reach the final decision.

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Overcoming the Barriers to Commercial CO_2-EOR in Alberta, Canada
Part I: Introduction & Technical Review of RCP & IETP CO_2 – EOR Pilots

BACKGROUND

The Western Canadian Sedimentary (WCSB) basin is the most productive petroleum basin in Canada being divided into two basins, the Alberta basin (occurring mainly in Alberta and NE British Columbia) and the Williston Basin (occurring mainly in Saskatchewan and SW Manitoba). The WCSB is considered a mature petroleum basin with regard to development because of the extensive infrastructure with most of the conventional oil and gas fields discovered and produced through primary production and water flooding as the preferred secondary recovery process. In some cases this has been followed up with tertiary recovery methods by HC-EOR (hydrocarbon miscible floods) and in two cases CO_2-EOR projects in the Viking Formation in Alberta and Midale Formation in Saskatchewan.

Initial production in the WCSB started in 1914 with the discovery of the Turner Valley field, SW of Calgary. By far the biggest discovery was at Leduc in 1947, just south of Edmonton. Commercial unconventional oil production started in 1967 with the strip mining of the oil sands and separating of the oil by hot water flotation. Following this, in situ recovery from the oil sands has been successful through the use of steam in twinned horizontal wells in an enhanced oil recovery process (EOR), also termed steam-assisted gravity drainage (SAGD). Recently, commercial development of low permeability oil reservoirs has been successful with the application of horizontal wells and multistage fracing.

EOR processes are based on either increasing the capillary number (which reduces the interfacial tension between two phases) or lowering the mobility ratio or both. The two most common EOR processes used globally are injection of steam or CO_2. They are complimentary in that steam is used in for shallow oils of lower API gravity which won't flow at reservoir temperatures and CO_2 is used for deeper oils of higher API gravity at pressures where the CO_2 is completely miscible (i.e. Minimum Miscibility Pressure; MMP).

Miscible displacements in the laboratory result in nearly 100% ultimate oil recovery. Reservoir scale displacements recover much less due to reservoir heterogeneity or viscous instability (mobility) which causes the solvent to bypass some of the oil. Immiscible displacements are not as effective but still may recover the oil by swelling, viscosity reduction and pressure build up. In the case of carbonates and CO_2, permeability increase may also result from partial dissolution of the carbonate rock.

In Alberta, HC (hydrocarbon solvent) floods developed in preference to CO_2 floods as a tertiary recovery method as the lighter HCs were readily available compared to CO_2 as a result of other oil and gas operations. Exactly, the opposite occurred in the U.S. where natural reservoirs of CO_2 were readily available and were exploited for CO_2-EOR. As a result, over 90% of the CO_2-EOR production in the world occurs in the U.S.. The two processes are different. CO_2 floods operate by a vaporizing gas drive where the intermediate hydrocarbon components of the oil are transferred to the CO_2 solvent. HC floods operate by condensing or rich gas drives where the light components are transferred from the HC solvent to the crude oil.

Miscible CO_2 floods are appealing because the CO_2-charged oil mobility increases relative to the original oil; and the interface between the oil and CO_2 disappears so that the displacement efficiency increases. Additionally the residual oil saturation is substantially reduced from values as high as 20% of pore space to values approaching zero in a water wet reservoir. In other words, the mobile oil is increased substantially compared to an oil reservoir that is produced on either primary or waterflood.

To achieve miscibility, the reservoirs must be deep enough to be able to raise the reservoir pressure above the MMP. This can be done by increasing the injection rate above the production rate; either by increasing the injection rate, reducing the production rate or both.

A challenge is to dissolve the CO_2 in the oil because of the much higher mobility of the injected CO_2 relative to the oil which results in the CO_2 bypassing the oil before it can completely dissolve in it; and the decrease in the diffusion rate of CO_2 dissolving in the oil for heavier oils. To counteract the tendency for the CO_2 to bypass the oils, most CO_2 floods utilize a tapered Water Alternating Gas (WAG) strategy where the water slugs gradually increase in size relative to the CO_2 slugs over time. This comes at a price as injectivity is generally reduced due its effects on relative permeability and water blocking. Additional water handling becomes a significant part of the cost of the operations as it needs to be processed initially to make sure that it will not be detrimental to the reservoir (e.g. clay swelling, reservoir souring, corrosion due to dissolved O_2) and the produced water which is not recycled needs to be disposed of in a deep well. Pumping requirements may change as CO_2 injection and water injection are alternated. Consequently, water injection should be minimized and only started once breakthrough of the CO_2 to production wells is seen, to control excess CO_2 production and should be implemented on a pattern by pattern basis.

Rather than use water to improve the displacement efficiency, CO_2 foams created by using surfactants offer an alternative to decrease the mobility of CO_2 if the foams can remain stable and not collapse when injected into the formation. Recently, instead of surfactants, silica nanoparticles have been used (at the University of Texas and New Mexico tech) to stabilize the surface/interface of the CO_2 bubbles composing the foam which have prevented the bubbles from coalescing but these foams have yet to be field tested. No major improvements in commercial application of CO_2 foams to EOR have been made over the past 20 years.

The other technical factor besides the displacement efficiency that determines the success of a CO_2 flood is the volumetric sweep which is affected by the gravity and the geological heterogeneity of the reservoir. The CO_2 will tend to sweep the top of the reservoir due to gravity while the water flood will sweep the bottom of the reservoir due to gravity. Heterogeneity will affect this process due to the changes in absolute permeability.

Beware of the often quoted statement "If it is a good waterflood, it could be a good CO_2 flood, but if it is a bad waterflood, it will be a terrible CO_2 flood". If pressure maintenance is not a problem, a poor waterflood is probably related to geological heterogeneity or permeability. CO_2 floods can perform more satisfactorily in lower permeability reservoirs than waterfloods. Reservoir heterogeneity can be addressed by infill drilling or horizontal wells with multistage fracing if a good geological model has been prepared. This has been demonstrated at Weyburn where horizontal wells are extensively used. Typically, CO_2 foods will be on a smaller spacing (e.g. 10 acres) if horizontal wells are not used. Alternatively, reservoirs with poor continuity between wells often respond well to cyclic injection. However, the lost oil production during the injection and soak periods may make a cyclic project uneconomic.

In the case of a thick reservoir such as the Redwater reef near Fort Saskatchewan, gravity displacement can be used, were the CO_2 is injected at the top of the reservoir and displaces the heavier oil vertically to flow into the producing wells which are completed at the base of the mobile oil zone. In this case, miscibility between the oil and the CO_2 is not necessary. The rate of injection has to be balanced to maintain a stable horizontal displacement front. Gravity displacement can also be used where fractures increase the vertical permeability

Commercial CO_2-EOR is predicated on minimizing the gross CO_2 utilization factor (mcf CO_2/bbl oil). Classically, a nominal hydrocarbon pore volume (HCPV) of approximately ½ was touted as the optimum amount of CO_2 to inject in a reservoir due to economics based on the price of CO_2 and the water/oil cut. However, the more CO_2 you inject, the more oil you recover. It follows that for lower price of CO_2, the more HCPV of CO_2 can be injected in a commercial project. This is one reason why the "marriage" of CO_2-EOR and CCS is inevitable. CCS is strictly a CO_2 storage project as CO_2 is regarded as a waste stream compared to CO_2-EOR where CO_2 is a valuable commodity. Obviously these two different views of CO_2 cannot be maintained and need to merge into one. This will be driven by government policy and the resulting regulations. If CCS becomes a mainstream activity to reduce CO_2 emissions, then the price of CO_2 will drop drastically and at the same time increase the oil reserves. In the case, where a reservoir has not been waterflooded, CO_2-EOR could become a secondary recovery process.

JUSTIFICATION FOR THE STUDY

Carbon dioxide capture and storage (CCS) in geological media has been identified worldwide as a major near-to-medium term strategy to reduce anthropogenic carbon dioxide (CO_2) emissions into the atmosphere. CO_2-Enhanced Oil Recovery (EOR) is recognized internationally as a form of CCS because 30-50% of the CO_2 injected is retained in reservoirs (see for example Faltinson and Gunter, 2008). The Weyburn-Midale CO_2-EOR project is the world's largest EOR project using an anthropogenic CO_2 source.

CO_2-EOR opportunities in the U.S. and Canada are considered significant. In the U.S., an incremental oil recovery of 3 million barrels of oil/day is said to be achievable by 2030 (ARI, 2009). At an oil price of \$70/barrel and delivered costs of CO_2 at \$15/tonne (\$0.79/Mcf), 66 billion barrels of oil would be economically recoverable at a utilization factor of 5 Mcf CO_2/bbl oil (ARI, 2009). Similarly, a number of studies have concluded that CO_2-EOR potential in Alberta is also significant (e.g. AOSTRA, PTAC, Alberta Research Council).

However, the only current commercial CO_2 floods in Alberta are in the Joffre and Chigwell Viking Pools. The first of which was initiated in 1984 with the encouragement of Alberta Oil Sands Technology and Research Authority (AOSTRA). The Alberta Department of Energy (ADOE) has offered programs to encourage CO_2-EOR at the pilot stage. Pilots have been completed in Apache Canada's Zama Keg River oil pool project in northwestern Alberta, Devon Canada Corporation's Swan Hills oil field (unit 1) project, Penn West's South Swan Hills project and Pengrowth's Judy Creek project in central Alberta, Penn West Petroleum Limited's Pembina Cardium oil pool project in central Alberta, CNRL/Anadarko Canada Corporation's Enchant Arcs oil pool project in southern Alberta and ARC Resources' Redwater project in central Alberta and others. None of these have developed into commercial projects with the possible exception of Apache's pinnacle reef oil pools.

Besides the Weyburn CO_2-EOR project in Saskatchewan, Husky Energy is planning to initiate CO_2-EOR projects using CO_2 captured from their ethanol plant.

This paradoxical situation raises a few important questions: if CO_2 -EOR has a great potential, why is little commercial CO_2 -EOR taking place in Alberta? Why are there fewer CO_2-EOR pilots running today than five years ago? If CO_2-EOR is the commercial road to early CCS projects, should companies be planning commercial CO_2 – EOR projects? Besides CO_2 supply, are there other barriers for CO_2 -EOR in Alberta?

OBJECTIVES

The ultimate objectives of this study are to review past and existing CO_2-EOR pilots and commercial operations in Alberta and Saskatchewan to:

- Identify major technical barriers for commercial development of CO_2 -EOR in Alberta
- Perform an analysis on how these barriers may be overcome
- In view of these barriers and to the degree these barriers may be overcome, recommend a methodology for Alberta to overcome these barriers
- Initiate discussions for new pilots or commercial CO_2-EOR projects in Alberta.

SCOPE

In preliminary discussions with stakeholders, who have interests in the efficient development of the Western Canadian Sedimentary basin's remaining oil resource, a number of major issues/barriers have been identified:

(1) CO_2 supply: 95% plus purity CO_2 is needed for EOR. Currently, CO_2 supply cost (capture and transportation infrastructure) is too high in Alberta. What is an acceptable price for CO_2 supply in order to implement CO_2 – EOR projects?
(2) Unitization: Unitization of Alberta's major oil fields is required to provide the integration and size necessary to make financing projects attractive, once a cheap supply of CO_2 is available. What can be done to make Unitization more effective?
(3) Reservoir characteristics and production history: Some have suggested that the majority of Alberta's oil reservoirs are less ideal for CO_2 -EOR, due in part to certain reservoir characteristics and production history. What are the characteristics of Alberta reservoirs that would make them attractive for CO_2 – EOR?
(4) Competing technologies: CO_2-EOR has to compete with technologies such as improvements in horizontal wells with multistage fracing, infill drilling, waterflooding, and other EOR solvents displacing CO_2-EOR. Horizontal wells with multistage fracing may deliver faster and better return on investment. Is there an opportunity to transition to CO_2 – EOR at a later stage?
(5) New oil reserves: The emergence of commercial tight oil recovery (e.g. Bakken) has significantly increased total oil reserves lessening the need for tertiary oil recovery. Is there an opportunity to transition to CO_2 – EOR after primary recovery?
(6) Role of CCS: How can CCS have a positive influence on CO_2 – EOR? What are the additional requirements to convert a CO_2 – EOR project to CCS and the impact that these requirements would have on a CO_2 – EOR project?

Other studies are addressing issues 1 and 2, so they will be analyzed in less detail. The main focus of this study is on the remaining barriers (4 to 6) which are mainly technical barriers. To answer these questions, a review of past and existing CO_2 - EOR pilots and commercial operations in Alberta and Saskatchewan has been completed. Depending on the pilot and commercial information available, not all aspects of these technical barriers have been addressed. Based on these analyses, a list of recommendations as to how these barriers may be overcome to make CO_2 EOR more attractive in Alberta has been made.

ALBERTA PILOTS AND COMMERCIAL OPERATIONS

The Alberta pilots have the following objectives:

- Prove the ability to safely inject and produce CO_2 with minimal corrosion, scale or asphaltene problems
- Evaluate the recovery of trapped hydrocarbon solvent if an HC flood preceded the CO_2 flood
- Evaluate the recovery of incremental oil
- Confirm the reservoir simulation model predictions of CO_2 storage and CO_2 enhamced oil recovery

There were 7 CO_2 –EOR pilots supported by the Alberta Department of Energy (ADOE) Royalty Credit Program (RCP) and the ADOE Innovative Energy Technology Program (IETP). In terms of this support the companies had to adhere to the Energy Resources Conservation Board (ERCB) mandated voidage replacement, minimum and maximum reservoir pressure, minimum miscible fluid volume, specified miscible fluid and production fluid sampling and analysis, and supply annual reports which were and are being released to the public after 2 years of confidentiality. The technical data in these reports provided well mechanical, injection, production, pressure and compositional data as well as problems encountered on a temporal basis. Unfortunately, the data is not reported in a standard fashion for each pilot and consists of a series of graphs, as well as monthly, annual and cumulative data for most of the data. Reporting of daily data is rare. Ideally the data needed to do a detailed analysis are daily tables with cumulative monthly, quarterly, annual and total amounts both by individual well and the sum for all the wells of produced water, oil, CO_2 and sales gas and injected CO_2 and water. Detailed pressure data is also needed as well as pool dimensions and saturations. Only a high level assessment of the existing data was completed in this report due to budgeted effort. Cumulative injection and production data were extracted from tables and when these did not exist, the report graphs were used to predict the values.

The data extracted from the ADOE supported 7 CO_2 EOR pilots are shown in Table 1a, 1b & 1c as well as average properties of existing commercial operations in Alberta and Saskatchewan. The characteristics of the pilots are summarized individually. Table 1a contains the properties of the carbonates pilots including the second and third largest oil pools in Alberta (i.e. Swan Hills and Redwater). Piloting was extended to two other large reefs in the Swan Hills area (i.e. South Swan Hills and Judy Creek) which are also listed. The Enchant Arcs pools, a much smaller carbonate oil pool in Southern Alberta was included. Finally, the highly successful commercial Saskatchewan Weyburn project's properties are listed. Table 1b incorporates six of the many pinnacle reefs of Zama in northern Alberta. Although a CO_2 flood was run in Pinnacle X2X in the 1990s by Pennzoil, it was not part of the RCP/IETP funded pilots and is not analyzed. Finally Table 1c compares the sandstone pools represented by those in the Viking containing the oldest commercial CO_2-EOR project in Canada to a pilot in the largest oil pool in Alberta, the Pembina Cardium. These property tables form the basis for a high level screening of these oil pools which is carried out later in this report. These properties are grouped into Fluid, Reservoir or Pool, and Pilot Properties. Each of these CO_2-EOR projects are described individually following these property tables. The fluid properties were obtained from an ERCB (2011) compilation except for viscosity which was obtained from a tabulation of Sproule, 2012. The Reservoir properties were obtained from the same ERCB compilation except for aquifer support, gas cap presence and heterogeneity. Permeability data was from the Sproule compilation. As mentioned before, the pilot properties were extracted from the RCP/IETP reports except for the pool areas which came from the ERCB compilation. The number of wells in the pools came from the Sproule, 2012 compilation. For the commercial projects, data for the Joffre Viking was from inception to the end of 2002; and data for the Weyburn project was for Phase A from 2000 to 2010.

The biggest uncertainties in the data lay in the water injection and production data which often is only shown in graphs. Most of the data for the pilots was taken from a series of reports (see the reference section) as was the data for the Joffre Viking. However for Weyburn, the data was scattered and often had to be estimated. For example, cumulative produced CO_2 was estimated by assuming the purchase to recycle CO_2 ratio being approximately 1:1 for Phase A in 2010. Cumulative water production was estimated from a changing WOR of 85% at startup of Phase A to 70% in 2010. Cumulative water injection was estimated from a WAG ratio of 0.8.

Table 1a: Properties of Alberta CO_2 EOR Pilots and Weyburn in Carbonate Pools

Class	***Property (units)***	***Swan Hills***	***S. Swan Hills***	***Judy Creek***	***Redwater***	***Enchant Arcs/ A&B***	***Weyburn Phase A to 2010***
		Devon	***PennWest***	***Pengrowth***	***Arc Res.***	***CNRL)***	***Cenovus***
Fluid Average Field Properties	**Depth (m)**	2426	2537	2629	984	1356	1450
	Init. Pressure (MPa)	20.2	21.6	22.6	7.8	11.9	14.1
	Temperature (^{o}C)	95	101	96	34	35	63
	Density (t/m^3)/API^o	0.820/41	0.82/41	0.82/41	0.84/36	0.90/26	0.88/29
	MMP (MPa)	21	18	23	9	11	16
	Viscosity (cp)	3.65	3.65	3.69	7.36	48.5	3.2
	S_{oil} initial	0.81	0.84	0.84	0.75	0.8	0.65
Reservoir or Pool Average Field Properties	**OOIP (10^3. m^3)**	458,000	151,100	126,200	198,000	1,743	222,500
	Cum. Prod. (10^3·m^3)	142,220	62,808	58,124	134,152	590	69,000
	Thick (m)	36	23	25	51	9.42	25
	Porosity (%)	8	8.4	9	6.5	14	20
	Permeability (md)	?	?	65	1411	?	3-50
	Aquifer Support	?	?	?	Yes	No	No
	Gas Cap	No	No	No	No	No	No
	Heterogeneity.	?	?	No fract.	fractures	?	fractures
Pilot Properties	**Area/Spacing (h/a)**	88,726/80	17,403/80	13,057/80	17,236/	204/40	18,100//20
	Infrastructure #well	1420//5/1	341//6/2	360//4/1	1074//5/1	//3/2	900//114/46
	Technology (wells)	Vertical	Vertical	vertical	vertical	vertical	V + H
	Water inj. (m^3)	94,258	398,803	360,069	0	37,650	18,666,667
	Water prod. (m^3)	1,181,000	546,742	1,414,010	789,919	52,240	19,077,900
	CO_2 inj./well (t/d)	167	199	221	260	95	200
	CO_2 inj. (tonne)	43,982	68,700	65,564	121,081	56,434	14,000,000
	CO_2 inj. (fct. HCPV)	.14	.13	.26	.10	.06	0.50
	CO_2 inj. time (days)	597	809	800	850	1,306	3,650
	CO_2 prod.. (tonnes)	7,917	3,482	16,980	60,932	~0	6,000,000
	Incr. oil prod. (bbl)	32,300	70,390	94,306	114,692	23,800	30,000,000
	Incr solv. prod(boe)	27,500	1,634	19,607	0	9,895	0
Production -P/W/S/CDH or CDV		P/W/S/CDH	P/W/CDH	P/W/S/CDH	P/CDV	P/CDH	P/W/CDH

P=Primary; W=Waterflood; S=Solvent Flood;CDH=Horizontal CO_2 flood; CDV=Vertical CO_2 Flood
Infrastructure = # of wells: by field//by pilot – producers/injectors
Area = area of pool in hectares / Spacing in acres= well spacing of pilot including injectors
? = not available for this report

Table 1b: Properties of Alberta CO_2 EOR Pilots at Zama in Carbonate Pools

Class	***Property (units)***	***Zama Keg River/Apache (X2X is Pennzoil)***					
		F	***G2G***	***NNN***	***RRR***	***Z3Z***	***X2X***
Fluid Properties	**Depth (m)**	1495	1510	1532	1551	1534	1498
	Pressure (MPa)	14.4	14.1	15.3	15.2	14.3	12.5
	Temperature (^oC)	71	76	80	73	79	76
	Density(t/m^3)/API^o	0.85/35	0.84/36	0.84/36	0.83/39	0.83/39	0.84/36
	MMP (MPa)	16	16	15	14	14	?
	Viscosity (cp)	8.56	7.36	7.36	4.76	4.76	?
	S_{oil} initial	0.87	0.87	0.85	0.85	0.85	0.84
Reservoir Properties	**OOIP ($10^3.m^3$)**	532	591	562	1118	394	650
	Cum. Prod.($10^{3\cdot}m^3$)	186	151	175	198	204	291
	Thick (m)	51	34	70	42	42	31
	Porosity (%)	7	8	7	10	8.6	7.5
	Permeability (md)	9850	161	61	?	?	2,994
	Aquifer Support	Weak	Weak	Strong	Weak	Weak	?
	Gas Cap	No	No	No	No	?	?
	Heterogeneity.	No fract.	No fract.	No fract.	?	?	?
Pilot Properties	**Area/Spacing (h/a)**	20/49	31/77	17/42	45/111	17/42	42/104
	Infrastructure #well	2//1/1	2//1/1	2//1/1	2//1/1	2/1/1	?
	Technology (wells)	Vertical	Vertical	Vertical	Vertical	Vertical	?
	Water inj. (m^3)	0	0	0	0	0	?
	Water prod. (m^3)	17,231	10,499	0	0	2136	?
	CO_2 inj./well (t/d)	60	190	120	190	190	?
	CO_2 inj. (tonne)	10,513	36123	25,009	25,940	47,304	?
	CO_2 inj.(fct.HCPV)	?	?	?	?	?	?
	CO_2 inj. time(days)	378	561	402	549	1102	?
	CO_2 prod.(tonnes)	0	23,977	0	0	72,515	?
	Incr. oil prod. (bbl)	16	49,810	0	0	199,418	?
	Incr solv. prod(bbl)	0	9,143	0	0	27,600	?
Production -P/W/S/CDH or CDV		P/W/CDV	?	P/W/CDV	P/CDV	P/CDV	?

P=Primary; W=Waterflood; S=Solvent Flood;CDH=Horizontal CO_2 flood; CDV=Vertical CO_2 Flood
Infrastructure = # of wells: by field//by pilot – producers/injectors
Area = area of pool in hectares / Spacing in acres= well spacing of pilot including injectors
? = not available for this report

Table 1c: Properties of Alberta CO_2 EOR Pilots and Commercial in Sandstone Pools

Class	***Property (units)***	***Pemb. Cardium/Penn West***		***Chigwell/Glencoe Resources***		***Penn West 1982 - 2002***
		Vertical W.	***Horizontal***	***E Viking***	***I Viking***	***JoffreViking***
Fluid Properties	**Depth (m)**	1551	1551	1386	1411	1400
	Pressure (MPa)	20.4	20.4	9.9	7.4	7.7
	Temperature (^oC)	46	46	58	59	51
	API (^{o})	0.83/38	0.83/38	0.86/38	0.84/39	0.82/38
	MMP (MPa)	12	12	14	?	12
	Viscosity (cp)	5.48	5.48	5.56	5.11	5.41
	S_{oil} initial	0.85	0.85	0.62	0.61	0.64
Reservoir Properties	**OOIP (10^3. m^3)**	1,488,000	1,488,000	8058	2097	14,120
	Cum. Prod.($10^{3.}m^3$)	205,996	205,996	476	321	6699
	Thick (m)	7.25	7.25	3.18	1.96	2.73
	Porosity (%)	12	12	13	13	13
	Permeability (md)	30	?	73	44	349
	Aquifer Support	?	?	?	?	?
	Gas Cap	No	?	No	No	No
	Heterogeneity.	Fractures	Fractures	Fractures	Fractures	No fract.
Pilot Properties	**Area/Spacing (h/a)**	293,534/	293,524	3829/	1499/	7977/
	Infrastructure #well	//6/2	?	61/7//	30/8//	422/20//
	Technology (wells)	Vertical	Horizontal	V + H	V + H	Vertical
	Water inj. (m^3)	6145	?	?	?	7,258,322
	Water prod. (m^3)	48,510	?	?	?	4,616,952
	CO_2 inj./well (t/d)	100	?	?	?	38
	CO_2 inj. (tonne)	94,019	?	?	?	2,153,064
	CO_2 inj. (fct. HCPV)	0.29	0.08	?	?	0.76
	CO_2 inj. time(days)	1386	?	?	?	X
	CO_2 prod. (tonnes)	10,129	?	?	?	1,290,522
	Incr. oil prod. (bbl)	39,941	?	?	?	3,648,200
	Incr solv prod(boe)	8,153	?	?	?	0
Production -P/W/S/CDH or CDV		P/W/CDH	P/W/CDH	P/CDH	P/S/CDH	P/W/CDH

P=Primary; W=Waterflood; S=Solvent Flood;CDH=Horizontal CO_2 flood; CDV=Vertical CO_2 Flood
Infrastructure = # of wells: by field//by pilot – producers/injectors
Area = area of pool in hectares / Spacing in acres= well spacing of pilot including injectors
? = not available for this report

Devon's CO_2-EOR pilot in the Swan Hills A&B pool

The Swan Hills Beaverhill Lake A and B pools, now called Commingled 001 were discovered in 1957 (Figure 1).

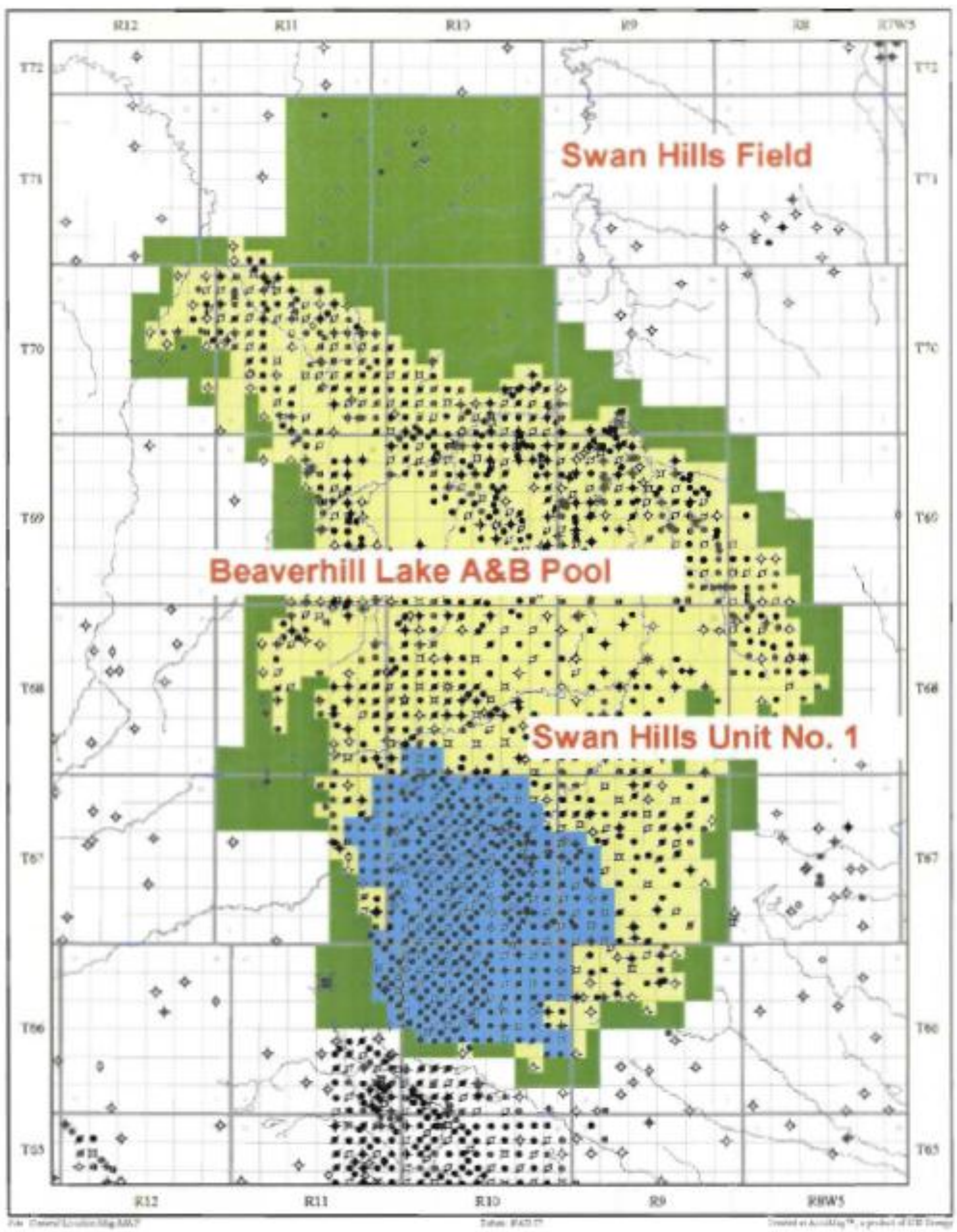

Figure 1: Swan Hills Beaverhill Lake A & B pools – well locations

The stratigraphy consists of 8 reef buildup units (B) above 5 carbonate platform units (P). The area selected (the uppermost interval, B6/B5 within pattern S of the Swan Hills # 1 unit, located in the structurally highest position of the reef complex) was previously flooded with hydrocarbon solvent (approximately 51% HCPV) from 1985 to 1995 and has been on terminal waterflood since May 1995. The reservoir pressure is above the MMP (21.1 MPa) for CO_2.

Excellent porosity and permeability exist in the B6 and B5 layers. At the northern end of the pattern, both layers are in vertical communication and laterally extensive. However, in the southern portion of the pattern, only the B6 is continuous and the B5 is quite tight. Permeability ranges from 0 to 300 md. The geological heterogeneity is seen in Figure 2 where the permeability is seen to closely track the porosity.

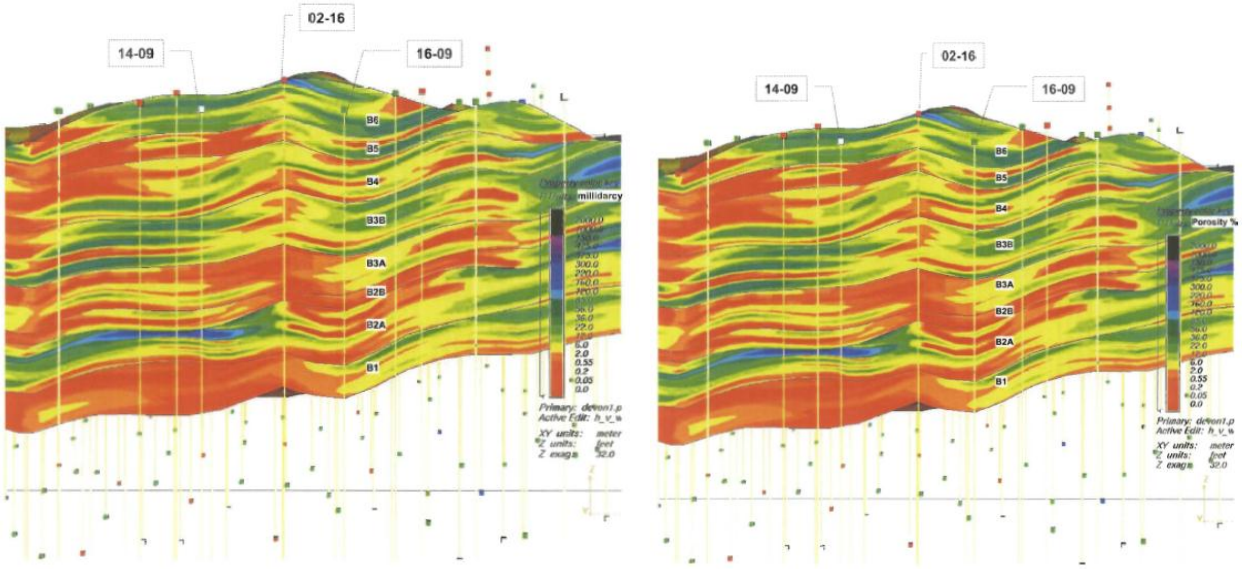

Figure 2: West – East cross-sections through the CO_2 pilot sliced at the CO_2 injector: Permeability (left) versus porosity (right).

The pilot (Figure 3) consisted of 6 reworked wells in a pentagonal pattern with one injector in the middle completed at a depth of 2443 mKB (8015 ft) below which the well was sealed with a packer and occupied approximately ¼ section or 160 acres overlapping into sections 09-, 15-, and 16-67-10W5 with a well spacing of 160 acres if the injector is ignored (approximately 80 acre well spacing including the injector). The area had been previously produced on primary, waterflooded, and HC miscible solvent flooded.

Figure 3: Devon Swan Hills CO_2 pilot well pattern. The perpendicular lines are the section boundaries.

A 1:1 WAG injection scheme was used with CO_2 being injected approximately every other month. Variable speed pumps were used to balance production from the 5 producers. Reservoir pressures were kept above the MMP. CO_2 injection was started in October 2004 and was terminated on May 26, 2006 with 13.6% HCPV (43,982 tonnes) of CO_2 being injected. Only three of the 5 producers showed a response. The original pilot simulations predicted that a response to CO_2 injection would be seen at all the producers by September 2005 (5 to 12 months after injection had started). Only one producer showed a response in that time period which included both enhanced oil production and recovery of hydrocarbon solvent. The amount of CO_2 injected was 43,982 tonnes (0.14 HCPV) over 597 days at a maximum rate of 167 tonnes/day and the amount of water injected was 94,258 m^3. The incremental production up to December, 2007 is estimated to be 32,300 bbl oil (63,000 bbls was originally predicted) and 27,500 boe (barrel of oil equivalent) of solvent for a total incremental recovery of 59,800 boe. An estimated 18% of the CO_2 injected into the pilot has been produced (7917 tonnes; original expectations were that 58% of the CO_2 injected would have been recovered), and 1,181,000 m^3 of water. There was no recycle CO_2 injected into the pilot. If a long term supply of CO_2 could be deliverable at an attractive price, a full-field commercial CO_2 project might be warranted.

Penn West's CO_2-EOR South Swan Hills Pilot (Beaverhill Lake A pool)

The South Swan Hills Beaverhill Lake Pool is located directly south of the Swan Hills Beaverhill Lake A&B pools (Figure 4).

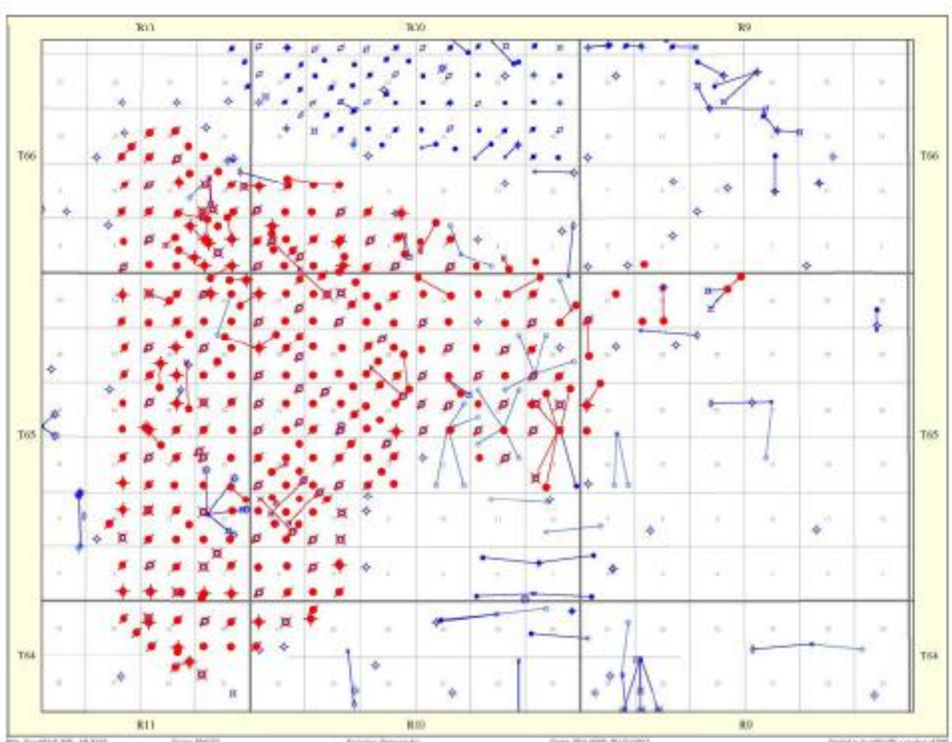

Figure 4: Swan Hills South Beaverhill Lake A – well locations

The reef can be divided into 5 stratigraphic zones. R1 represents the lowermost interval and is characterized by progradational lower, middle and upper foreslope, reef margin, reef flat, open lagoon and restricted lagoon facies. The following three stratigraphic intervals of R2, R3 and R4 represent the buildup stages of the reef and exhibit reef margin, open lagoon and restricted lagoon facies. The final cycle is R5 that is characterized by a ramp bounded shoal and forms an excellent continuous reservoir, and is isolated from the lower zones by a green shale. This was cemented off in the pilot area because it has been considered to have been largely swept by previous miscible HC flood schemes. Fracturing is minor and was not expected to affect the flooding scheme. The pilot targeted the HC flood bypassed oil where vertical sweep efficiency is relatively poor in lower zones below R5 where the highly interstratified rocks of transitional lagoonal to reef margin environments exist. There are two back to back 80 acre spacing inverted 5 spot patterns (Figure 5, well spacing for producers = 160 acres).

Figure 5: Penn West Swan Hills pilot (65 10W5)

CO_2 injection started in May 2008 and lasted until May 2010 over a period of 809 days. WAG was also initiated. Corrosion and asphaltene problems occured. Asphaltenes were controlled with inhibitors and higher producing backpressures. Corrosion was controlled with coated tubing and inhibitor application. 12.5% HCPV was injected with 1.7% incremental oil having been produced at end of pilot. Voidage replacement was ~1.4. A total of 68,700 tonnes of CO_2 for an HCPV of 0.13 at maximum injection rates of 199 tonnes/day/well and 398,803 m^3 of water were injected in the WAG process. A total production of 70,390 bbl of oil, 1,634 boe of solvent and 3,482 tonnes of CO_2 were produced. Higher productivity of the wells occurred than predicted possibly due to stimulation due to dissolution of the carbonates in the CO_2-charged water or the geological model's perm was low.

Pengrowth's CO_2-EOR Judy Creek Pilot

A quaternary CO_2-EOR pilot is being conducted at the Judy Creek Beaver Lake "A" Pool, a middle Devonian age carbonate reservoir at 2400 m depth in the R5 zone (Figure 6). The pool spans portions of four townships. The pilot pattern has previously undergone waterflood and hydrocarbon miscible flooding (18 months between 2002-2003. CO_2 (both purchased CO_2 and acid gas which contained a few % H_2S from the Judy Creek gas plant) injection in WAG mode began in 2007 targeting 60,000 tonnes CO_2.

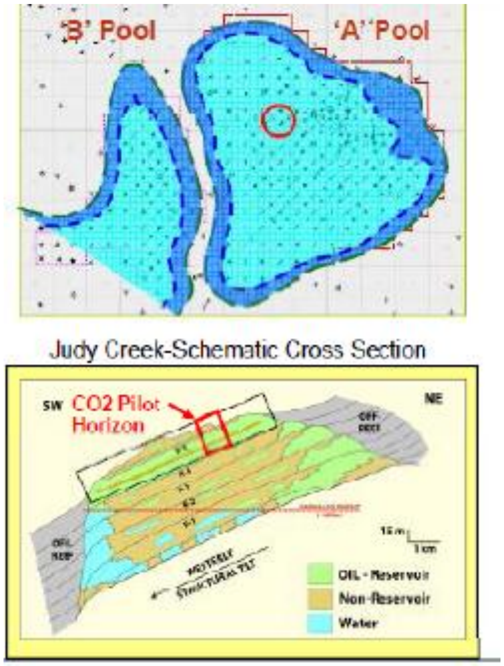

Figure 6: Judy Creek A pool CO_2-EOR pilot (after Sproule, 2012)

The pilot is located in an existing 80 acre pattern (Figure 7). Targeted recoveries were 3% OOIP and 40% of previously injected HC solvent.

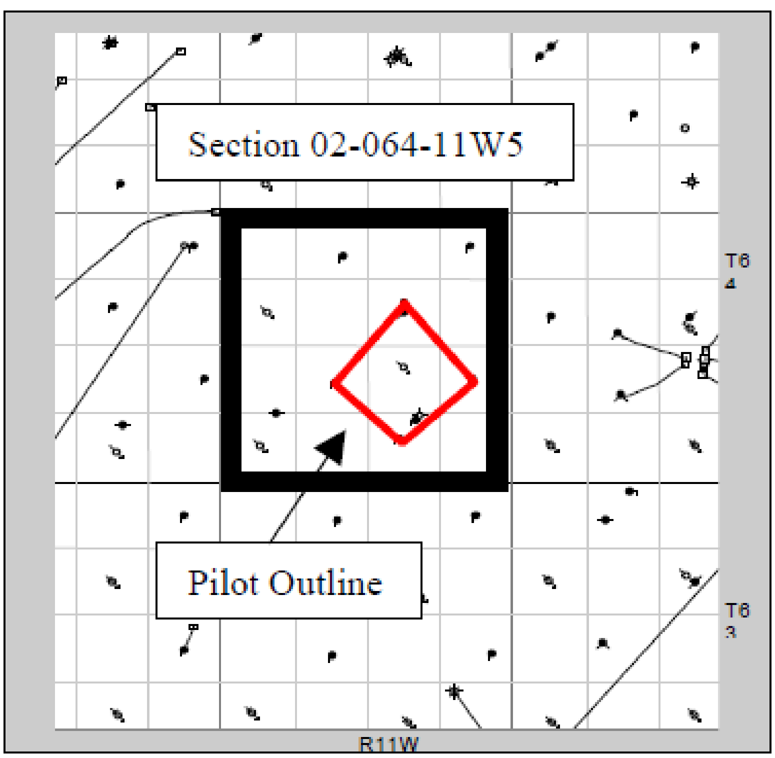

Figure 7: Pengrowth's CO_2-EOR pilot pattern on an 80 acre pattern

A baseline 3D sesmic was performed before CO_2 injection. Three years later a repeat seismic was performed. Figure 8 illustrates the change in acoustic impedance. A negative change in acoustic impedance (Blue) indicates water swept pathways, while a positive change in acoustic impedance (Red) indicates CO2 swept pathways. Interpretation of pathways is consistent with; production history to 02-02 & 06-02, geology to 08-02 & 10-02 and pattern tracer response. It appears that water and CO_2 swept different parts of the reservoir.

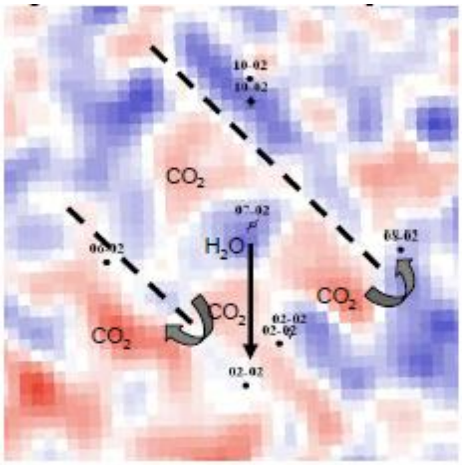

Figure 8: 4D seismic acoustic impedance (2009 – 2006)

The area had previously produced on primary, water flood and HC miscible flood. A total of 65,564 tonnes of CO_2 was injected (0.26 HCPV) over 800 days at maximum rates of 221 tonnes/day/well and 360,069 m^3 of water. Production resulted in 94,306 bbl of oil, 19,607 boe of solvent, 16,980 tonnes of CO_2 and 1,414,010 m^3 of water. Initial injection rates were lower than the previous HC miscible flood but steadily increased due to increased permeability from dissolution of the carbonate minerals in the reservoir. Reservoir pressure was controlled to be above the MMP of 23 MPa. For 30% of HCPV CO_2 injection, the pilot forecast was 2.3% of the OOIP and 25% recovery of the injected CO_2.

ARC Resources' CO_2-EOR Redwater Pilot

The Redwater reef is the third largest oil reservoir in Canada containing ~ one billion bbl OOIP. The oil bearing portion of the reef is small relative to the whole reef occupying approximately 5% by volume of the reef with the remainder of the reef water saturated which is aquifer supported as depicted in Figure 9. The Redwater Leduc reef complex is subdivided into the Lower, Middle and Upper Leduc members as illustrated in the schematic stratigraphic cross section of the Redwater reef complex shown in Figure 9. The Redwater Leduc D-3 pool is trapped in the updip northeast perimeter of the Upper Leduc Member. The Leduc is overlain by the calcareous and argillaceous shales of the Ireton formation. The original gross thickness of the oil zone in the pilot area is up to 61m and is underlain by the Middle Leduc, Lower Leduc and Cooking Lake aquifer.

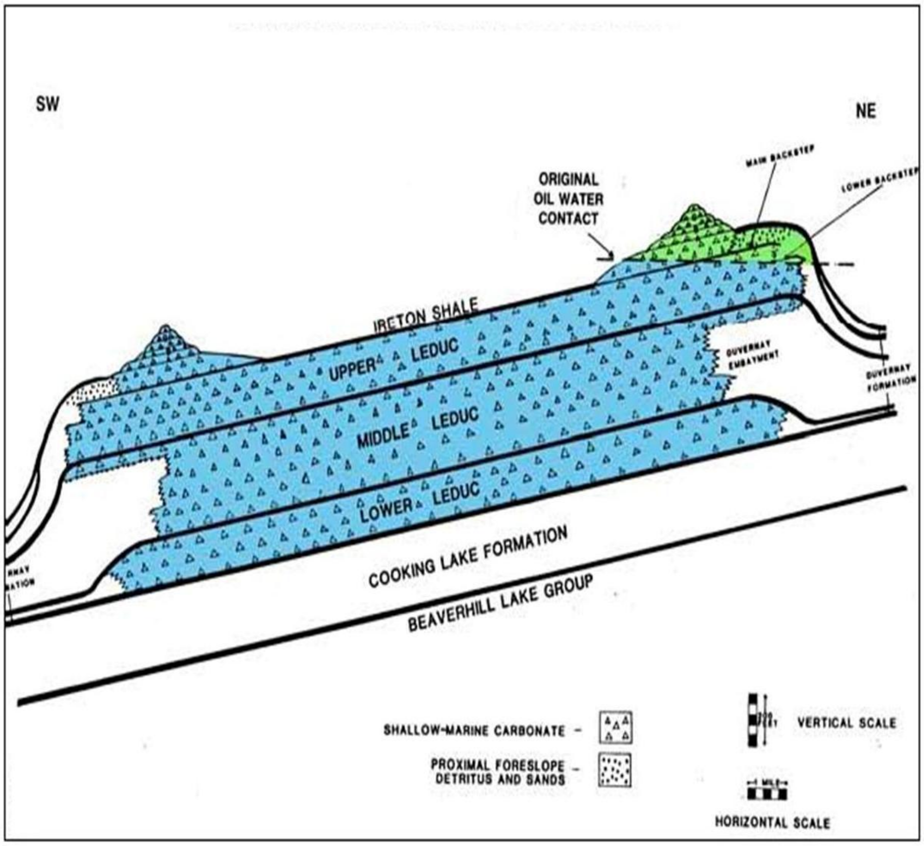

Figure 9: Redwater Reef showing oil and water zones

The three generalized facies present in the pilot area are Back Reef – Shallow water low-energy, stratified reef lagoon and tidal flat limestones. These limestones vary in composition from carbonate muds to carbonate sands and grainstones. The backreef facies (average porosity of 5.5% and average permeability of 50 md) is characterized by alternating permeable and impermeable beds. Generally the subtidal limestone beds are more porous and permeable than the subaerially exposed tidal flat limestones. The Main Reef Detritus (average porosity of 11% and average permeability of 550md) is composed of high energy grainstones with abundant stromatoporoid, bryozoan and skeletal debris. The main reef detritus is characterized by relatively high porosity and permeability. The Foreslope Facies (average porosity of 12% and average permeability of 200 md) are relatively homogeneous carbonate sands and coarser skeletal debris shed down the eastern margin of the main reef buildup. The foreslope facies is characterized by very homogeneous, high porosity and slightly lower permeability than the main reef detritus facies.

The project includes four existing production wells and a new production and injection well as seen in Figure 10. The well spacing in the Redwater Immiscible CO_2 Vertical Pilot Project is at 40 acres and the pilot is attempting to use gaseous CO_2 to mobilize oil in a vertical direction so the location of the pilot wells is based on structure and not on a typical pattern design.CO_2 injection started on July 29, 2008 at 9 tonnes/day and ramped up to a maximum of 120 tonnes/day with a total quantity of CO_2 injected of 61,000 tonnes. The original Redwater Leduc D3 reservoir pressure was 7,240 kPag and reservoir temperature was 35^{o}C at the pool datum depth of 355 meters sub-sea. Although the MMP was determined to be 9.0 MPa, increasing the reservoir pressure above the MMP was not practical because of the reef's connection to the regional Cooking Lake Aquifer (Figure 9). A slim tube test was conducted at the original reservoir pressure and only 80% of the oil was recovered after 1.2 HCPV of injection indicating that the CO_2 was not completely miscible even though a substantial amount of the CO_2 dissolved in the oil reducing the viscosity of the oil from 2 to 1 cp. Consequently a vertical flood was chosen because of the partial miscibility of the CO_2 and the low density of CO_2 (228kg/m^3) at the low reservoir pressure. The cumulative voidage replacement ratio (VRR) is expected to range from 1.35 to 1.86 while CO_2 is being injected and fall to 0.94 to 0.99 after injection is terminated.

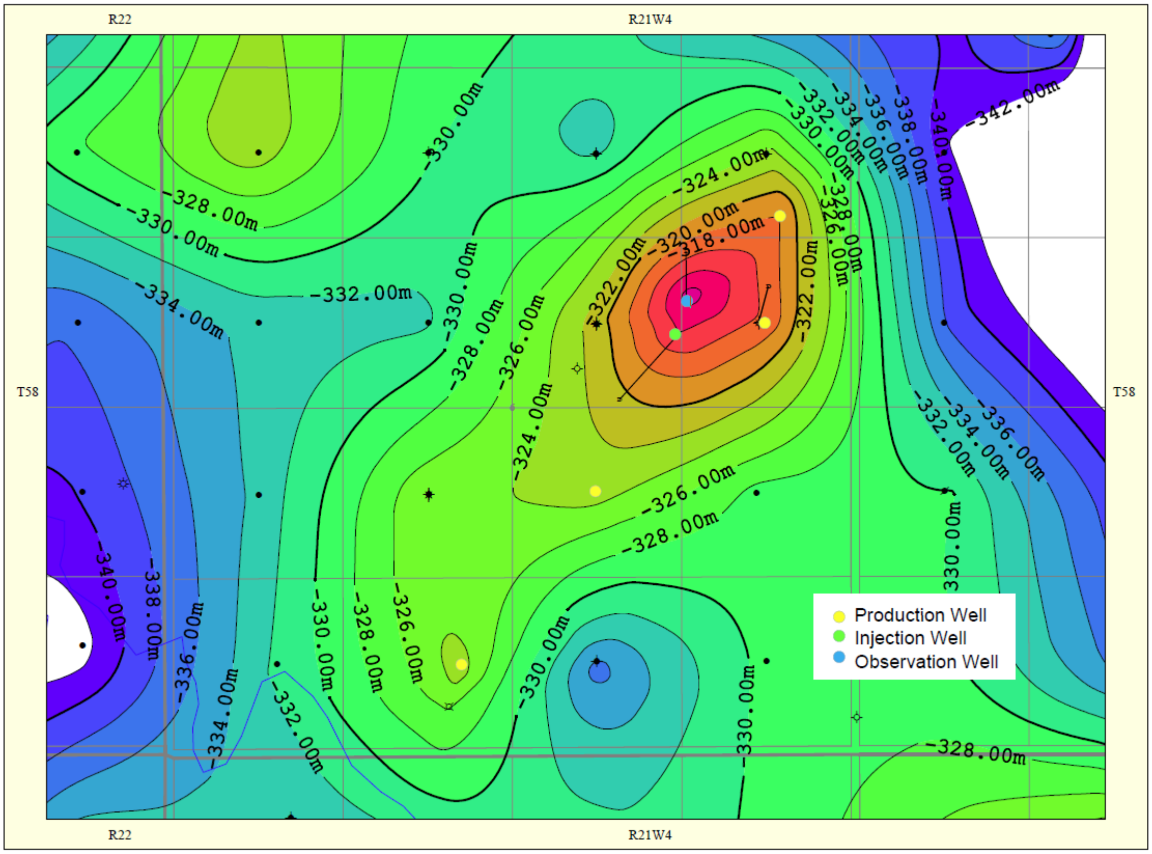

Figure 10: Location of pilot wells in Redwater reef contoured to show dome. Note that the 5th production well is not shown as it sits below the spill point but is necessary to bound the pilot on the east at 11-06-058-21W4. Other outlying wells are shown by black dots.

The estimated pool average residual oil saturation after waterflooding, Sor_w, is 25%. The CO_2 gravity displacement flood was expected to lower the residual saturation, Sor_o, to 15%. Reducing the production well drawdown had the most significant effect on reverse gas coning followed by shortening the length of the production interval. To maintain a stable gravity displacement flood, the flood advance was monitored by a fluid contact logging program in the observation well. Pulsed Neutron Decay (PND) logs were used to monitor the progression of the CO_2 water contact and Induction Array log for the progression of the oil water contact.

Because the production wells have been designed to use CO_2 lift, the recycle gas compressor can't handle the volume when significant CO_2 breakthrough occurs which is also accompanied by severe asphaltene deposition in the production wells. Both the asphaltene problem and the scale formed in the heater treater where the final amounts of CO_2 are liberated have been controlled by chemical additions.

The pilot area had been produced on primary, and though water disposal took place in the deeper parts of the reef, and there was active aquifer support, a waterflood was not carried out. Effectively, there is a natural waterflood due to the aquifer support. The cumulative CO_2 injected was 121,081 tonnes (0.10 of HCPV) over a 850 day period at a maximum injection rate 260 tonnes/day. No water was injected as this was a gravity displacement flood. The production was 114,692 bbl of oil, 0 boe of solvent, 60,932 tonnes of CO_2 and 789,919 m^3 of water.

CNRL/Anadarko's Enchant Arcs A & B pool CO_2-EOR Pilot

The late Devonian age pool is one of approximately 40 similar oil and gas pools found at depths of 1400 m within an area covering 10 townships in Southern Alberta. The reservoir consists of interbedded dolomitized grainstones and anhydrite deposited in a restricted lagoonal and sabkha environment behind a carbonate barrier bank. Complete dolomitization is responsible for the reservoir quality rock. The trapping mechanism is structural and results from multistage salt solution collapse of underlying units. The reservoir does not have an effective aquifer support. The geology of the pool is characterized by a fair degree of heterogeneity due to deposition and subsequent diagenesis. Consequently the geological model was subject to large uncertainties. This was compensated for by experimenting with different inter-well porosity and permeability distributions which yield a satisfactory match to historic pressure and production performance.

MMP was found to be 10.1 MPa for 98% CO_2 but rose to 13.5 MPa for CO_2 with 10% impurities (5% H_2S and 5% HCs). The minimum operating pressure set by the Energy Resources Conservation Board (ERCB) was 11.1 MPa.

The pilot has 1 injector and 3 producers as shown in Figure 11 (depicting Section 22-13-15W4) where each of the 16 squares represents a 40 acre LSD. It represents a ¼ of a 9 spot occupying approximately 80 acres with a well spacing of approximately 40 acres. Note that the pilot is only bounded by producers to the south and west and unbounded to the north and east.

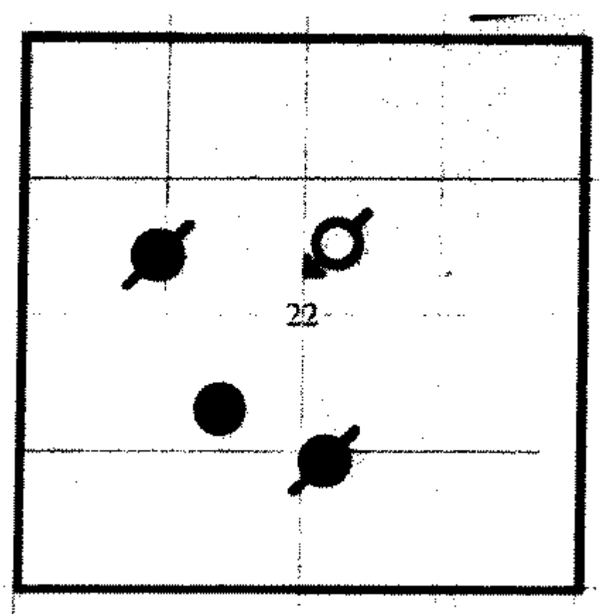

Figure 11: Anadarko's Enchant Arcs A&B CO_2 pilot well pattern. The internal perpendicular lines are LSD boundaries.

Previously the pool had only been produced on primary. CO_2 injection started on September 23, 2004 using CO_2 from a nearby gas processing plant and injection carried on until August 2008 in a WAG process. The target was to displace the oil from the smaller pores with the CO_2 solvent that were not saturated by water during the WAG process. Production is commingled between zones A and B which are separated by a shale layer. The desired water injection rates for the WAG cycle were not able to be maintained and the pressure fell below MMP several times during the project. CO_2 breakthrough occurred in only one of the three wells and enhanced oil rates were not observed. Total CO_2 injected was 56,434 tonnes during the project equivalent to 5.84% of the HCPV at maximum injection rates of 95 tonne/day. Water injectivity was addressed by drilling a new injector and 37,650 m^3 were injected. Production was 23,800 bbl oil, 9,895 boe of HC gas, 0 tonnes of CO_2 and 52,240 m^3 water. In the longer term, CNRL continued with a WAG operation in this and an additional pool (F & G) so that a steady stream of CO_2 could be utilized in a two pool WAG operation if a secure large supply of CO_2 could be found.

Apache's ZAMA basin Acid Gas Pilot project

The 880+ middle Devonian Keg River Pinnacle reefs (Figure 12) are the primary oil producers in the basin with the average size being 16 hectares (40 acres) at the base and 120 m in height with varying degrees of aquifer support. The reefs are typically dolomitized with varying porosity and permeability and both decrease to the tops of the reef.

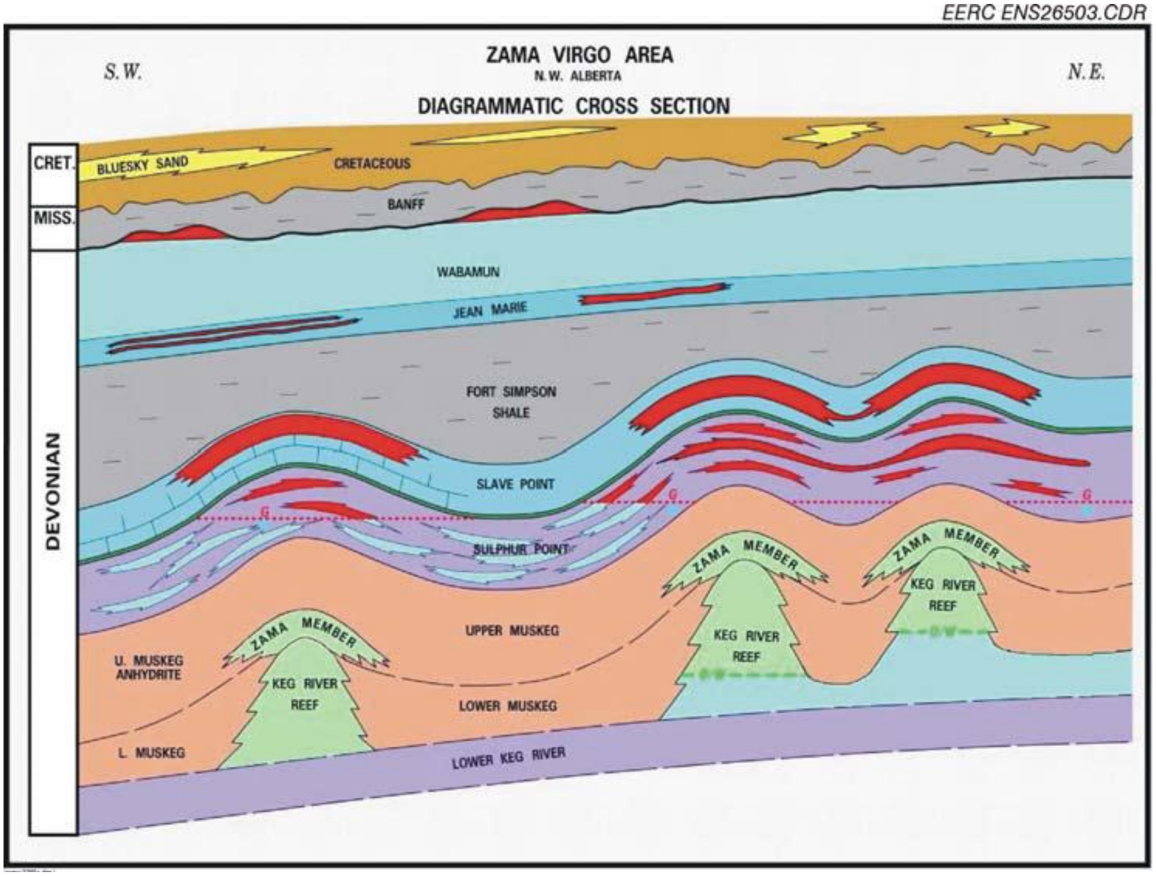

Figure 12: Schematic cross section illustrating the sedimentary succession encasing the pinnacle reefs in NW Alberta. Oil occurrences are by represented by the green, gas by the red and water by the blue.

Acid gas EOR lowers the cost of acid gas disposal from the gas processing plant as the produced oil can offset the cost of disposal of the H_2S component of the acid gas. Five Zama Keg River pinnacles/pools were selected for acid gas EOR: Z3Z, F, G2G, NNN and RRR. The Z3Z pool was previously used for acid gas disposal and originally only produced under primary production. This pool was initially depleted to a low reservoir pressure and is supported by a weak aquifer. The F pool was previously waterflooded to a high pressure of 21 MPa. The pressure was depleted to below 15 MPa. This pool is supported by a weak aquifer. The G2G pool was supported by a weak aquifer. After primary production, an offset waterflood in the YY pool contributed to production. The NNN pool was waterflooded previously and is supported by a strong aquifer. The RRR pool is supported by a weak aquifer and has undergone primary production.

Acid gas was injected into the crest of the structure and production was from the oil water contact using a gravity displacement scheme. Acid gas was used as the injectant commencing in December 23 2004 and continuing through December 2007 (the date covered by the final report) and whose composition was approximately 67% CO_2; 30% H_2S and the remainder methane. Total acid gas injection volume to the end of 2007 was 75,817,000m^3 of which 50,634,000m^3 was CO_2. Total breakthrough gas was 51,500,000m^3 of which 33,522,000m^3 was CO_2. Total CO_2 stored is 17,112,000m^3. Since no baseline existed for these 5 pools because of the modifications required to allow for the EOR scheme, Apache has no base production for these pools. They considered all current production to be incremental production.

For purposes of estimating potential oil recovery, residual oil was set at 5% for miscible flooding and 15% for immiscible flooding. Attaining MMP was an issue as the original reservoir pressure should not be exceeded. Two cases were distinguished: MMP for the original oil and the MMP for the depleted oil. Reservoir oil becomes depleted when reservoir pressure falls below the original saturation pressure resulting in a depletion of the lighter components from the reservoir. This depleted oil has a lower MMP between 10 and 20%, ranging from 14 to 16 MPa for the 5 pools (Table 1b)

Major issues with asphaltene and wax precipitation plugging pipelines resulted in stop and start operations which seriously affected the continuity of the pilots. The Z3Z pinnacle received the most acid gas and responded with significant oil production through a horizontal well in line with forecast volumes. However it was previously used for acid gas disposal after a period of primary production so considerable acid gas already existed in the reef when the EOR project started. During the pilot phase, 47,304 tonnes of acid gas were injected over 1102 day period at maximum injection rates of 190 tonnes/day. No water was injected. Production was 199,418 bbl of oil, 27,600 boe of natural gas, 72,515 tonnes of acid gas, and 2136 m^3 of water.

The G2G pinnacle also responded to acid gas injection but similarly to the Z3Z, it suffered severe wax hydrate plugging in the surface pipelines. The current recovery is about 1.4% of the OOIP with a HCPV injected of 5%. In the pilot phase, injection consisted of 36,123 tonnes of acid gas, over 561 days at maximum acid gas injection rates of 190 tonnes/day. No water was injected. Production consisted of 49,180 bbl of oil, 9143 boe of natural gas, 23,977 tonnes of acid gas and 10,499 m^3 of water.

The F pinnacle is in a dewatering phase and continues to produce 100% water during acid gas injection since the reef was fully depleted by water injection and the production is from below the water oil contact. Injection consists of 10,513 tonnes of acid gas over 378 days at maximum acid gas injection rates of 60 tonnes per day. Production consists of 16 bbl of oil, no acid gas or natural gas, and 17,231 m^3 of water.

The NNN and RRR pinnacles have only been exposed to acid gas injection with no production in order to build up the pressure to exceed the MMP. The NNN pinnacle has seen the injection of 25,009 tonnes of acid gas over 402 days at maximum injection rates of 120 tonnes of acid gas/day with no water injection. The RRR pinnacle has seen injection of 25,940 tonnes of acid gas over 549 days at maximum injection rates of 190 tonnes/day with no water injection.

Currently, all of the available acid gas from the Zama gas plant is being utilized as a miscible flood in the 5 pinnacles discussed above. Apache was planning to double the number of pinnacles flooded by bringing in acid gas from an external source. This did not happen as financial terms could not be negotiated with the third party.

Cenovus' Weyburn Commercial CO_2-EOR project
The Weyburn field contains approximately 1.4 billion bbl oil and has evolved through primary and waterflood production since 1955 with both vertical and horizontal infill wells drilled starting in 1987 and has been continuously CO_2 flooded since 2000 (ending in approximately 2025) (Figure 13).

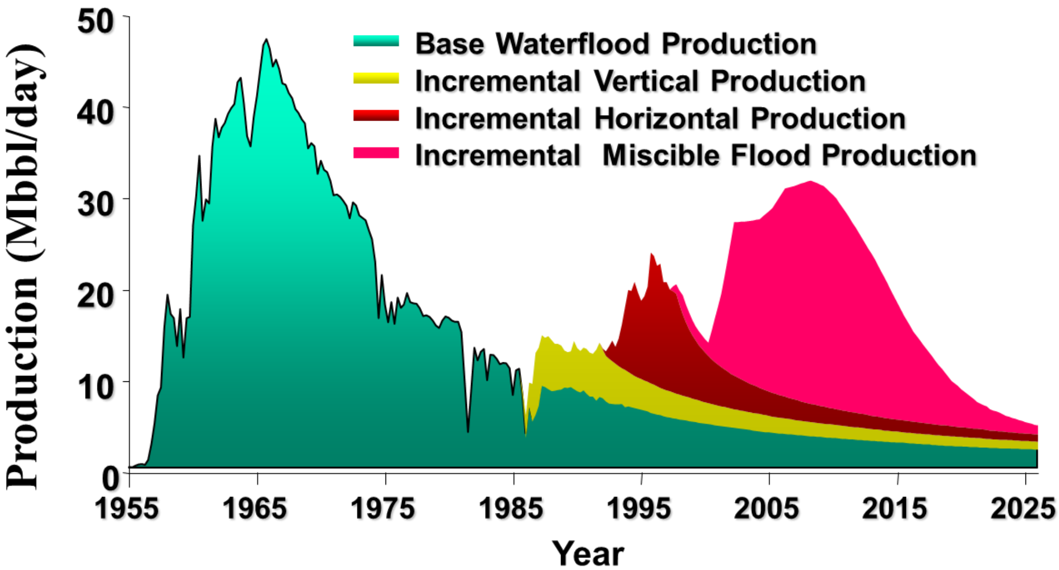

Figure 13: CO_2 injection for enhanced oil recovery at the Weyburn field, Saskatchewan (courtesy of EnCana, 2004)

The geology of the pool is contained in the tilted Mississippian Midale Beds of the Charles Formation consisting of a lower permeable limestone "Vuggy" zone overlain by the tighter dolostone "Marly" zone, in turn capped by the impermeable Midale Evaporite and underlain by the Frobisher Evaporite. The Vuggy unit was formed mainly in a marine lagoonal environment affected by carbonate shoal development, and is 10 to 22 metres thick with permeabilities averaging 20 md with approximately 15% porosity. The Marly unit, 0 to 10 metres thick, has higher porosity (averages 26%) but lower permeability and is the target of the infill horizontal wells and the CO_2 flood because it has largely been unswept by the waterflood. Fractures trend SW – NE and are more common in the Vuggy. In the north the Midale beds are truncated by the sub Mesozoic unconformity which forms the trap for the oil pool.

Four strategies were developed to exploit the Marly depending on the relative thicknesses of the Marly and the Vuggy:

1. SSWG -Separate but simultaneous injection of CO_2 and water in horizontal and vertical injectors, respectively in a line drive arrangement. The vertical water injectors were completed in the Vuggy while the horizontal CO_2 injectors were completed in the Marly. The purpose of the water injectors was to keep the CO_2 confined to the Marly while the water continued to sweep the Vuggy.

2. VWAG – Vuggy alternating water and gas using vertical injection wells. In areas of the reservoir where the Marly was absent, a WAG scheme was used in a line drive setup where the injectors for one pattern would be on CO_2 injection while the other pattern was on water injection and vica versa with pattern pairs across the fracture trend.
3. MVWAG – Marly and Vuggy alternating water and gas when Marly was present in a line drive setup with pattern pairs across the fracture trend with only vertical injectors. Compare to VWAG, there are horizontal producers in the Marly as well as the vertical producers completed in the Vuggy.
4. SGI – Straight gas injection is the same geometry as MVWAG except that CO_2 is being continuously injected in the Vuggy with horizontal producers in the Marly and vertical producers completed in the Vuggy.

The reservoir is at approximately 1450 metres depth at 63^{o}C, with initial pressure of 14 MPa, varying during waterflooding between 8 and 19 MPa, and during CO_2 flooding exceeding the MMP of 15-17 MPa. The initial target was 19 patterns expanding to 75 patterns over time as more recycle CO_2 becomes available. Currently, injection rates are approximately 5 Mt CO_2/yr with half of that being recycle CO_2 and oil production rates are 28,000 bbl/day with 18,000 bbl being incremental (Hitchon, 2012).

Complex schemes such as this require detailed monitoring of production and dedicated reservoir management – much more so than a waterflood. Infill drilling plays a large role in the development of the pool prior to and during the CO_2 flood. The horizontal wells, aligned parallel to the fractures were necessary to develop the thin tight Marly. In contrast the nearby, Midale field operated by Apache chose to align their horizontals wells perpendicular to the fracture trend even though both fields are in the same formation. Such apparent contradictions arise from the complex geology of these reefal successions and the changes in the orientations of the existing stress fields.

Penn West's CO_2-EOR Cardium Pilot

The pilot consisted of two 20 acre, back to back 5 spot patterns in Section 11-48-9W5 in an area which has seen no activity since 1996 except for one well being produced between 1998 and 2004 (Figure 14). At startup in 2005, reservoir pressure and temperatures ranged from 15.9 to 19.8 MPa and 49^{o}C compared to a minimum miscibility pressure of 12 MPa. Fence water injectors were used outside the pilot to raise the areas of lower pressures. Residual oil saturation was estimated to range from 30 to 50%.

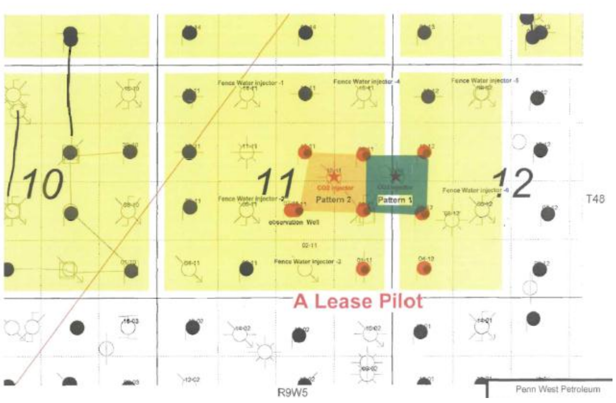

Figure 14: Pembina Cardium pilot location

The target injection zones were three sandstone units (3 metres thick) with intervening shale units (1 metre thick) between the upper and middle sandstone units and 5 metres thick between the middle and lower sandstone units. The injection zones were capped by a higher permeability thin conglomerate, possibly a potential thief zone. Average permeabilities decreased from 21 md in the upper and middle sandstones sandstones to 10 md in the lower sandstone unit.

The injection consisted of 94,019 tonnes of CO_2 (0.28 HCPV) at maximum injection rates of 100 tonnes /day over 1386 days and injection of 6,145 m^3 of water. Production consisted of 39,941 bbl of oil, 8,153 boe of natural gas, 10,129 tonnes of CO_2 (CO_2 breakthrough in the field was faster than the model predicted) and 48,510 m^3 of water. A WAG test carried out in the pilot, although lowering the gas to oil ratio (GOR), did not result in any enhanced oil production and was discontinued. An extensive monitoring program was carried out in parallel. The interpretation of the pilot production was complicated by a strong NE-SW preferential flow related to existing fractures. Good vertical sweep efficiency was obtained based on data collected from two infill wells. The oil processing rate was disappointing. As a follow-up, an adjacent pilot utilizing two newly drilled horizontal wells as producers was carried out but was not part of the ADOE funded program.

Penn West's Joffre Viking Commercial CO_2 – EOR Project
The Joffre Viking pool started primary production in 1953 with waterflooding starting in 1957, and a CO_2 flood in 1982. The pool is a long and narrow shoreline deposit (Figure 15) controlled by relative fluctuations of sea level. The Cretaceous Viking sand consisting of coarse grained to conglomeritic sandstone lies in a NW-SE and is 32 km long and 1.6 to 3 km wide. The Upper, Middle and Lower sandstones are separated by two erosional surfaces which impedes the vertical permeability. The average horizontal permeability is 500 md. The ratio of vertical to horizontal permeability is 0.1. The density contrast between the oil (650 kg/m^3) and the CO_2 (520 kg/m^3) at reservoir conditions is relatively small. The combination of the two properties was interpreted as contributing to minimizing gravity override of the injected CO_2. Any premature breakthrough was thought to be related to high permeability streaks, other geological heterogeneities or thin oil pay (Pyo et al., 2003).

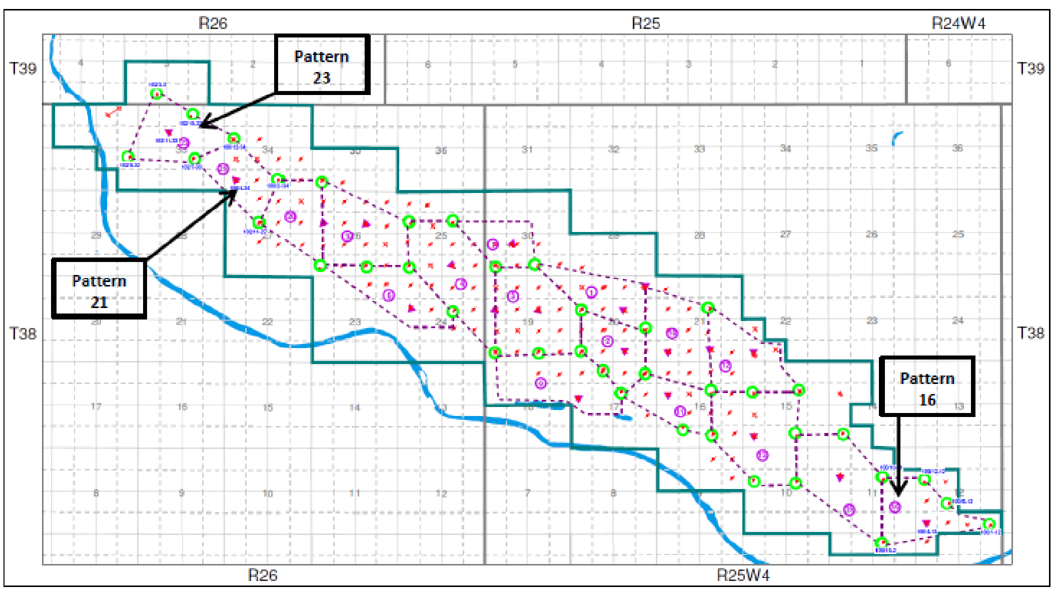

Figure 15: Well patterns in the Joffre Viking CO_2 – EOR Project as of 2007.

A total of 400 wells have been drilled on 16 ha (40 acre spacing). The pool was abandoned in the mid 1960's after 42% of the OOIP was produced. A CO_2 flood was initiated 20 years later with pressuring up of the reservoir and CO_2 pilot injection starting in 1984. After seven years of development and evaluation, a commercial CO_2 flood was started in 1991 with expected incremental recovery of 13%. By 2003, after over

20 years of continuous operation, the miscible flood had expanded to thirteen patterns containing 33% of the total OOIP in the Joffre Viking pool. Performance monitoring and management was done by pattern analysis by assigning the areas affected by each CO_2 injector and calculating production factors for each of the surrounding producers. Currently there are 23 patterns (Figure 15).

Prior to commercial development, it was recognized that large WAG cycles were not effectively controlling mobility of CO_2; CO_2 and water were effectively following different flow paths in the reservoir. Simultaneous injection of water and CO_2 was found to be more effective (Stephenson et al. 1993). By 2003, tertiary oil production amounted to 580,000 m^3 oil (12% of the OOIP from 13 patterns) with daily oil rates of 100m^3/day from 265,000 m^3/day CO_2 injection from 32 producers in 13 patterns. The produced gas stream contains 20% hydrocarbons which is recycled back into the reservoir along with the produced CO_2. The total CO_2 injected is 1,132 x 10^6 m^3 (40 bscf, 76% HCPV) of which 453 x 10^6 m^3 (16 bscf) remains in the reservoir. In addition to the CO_2, 2.6% HCPV of natural gas solvent has been stored in the pool. The gross utilization factor is 10.8 mcf/bbl oil (ranging from 3.5 to 24.9 by individual pattern) and the net utilization factor is 4.0 mcf/bbl oil (ranging from 1.7 to 9.9 by individual pattern). Average CO_2 injection rates are 20,000 m^3/d/well. Cumulative water injected is 7,258,322 m^3 and cumulative water produced is 4,616,952 m^3.

Glencoe Resources' Chigwell Viking Commercial CO_2 – EOR Project

The Chigwell Viking pools are light-medium oil underpressured sandstone reservoirs at a depth of approximately 1400 m similar to the Joffre Viking. Two pools are being flooded with CO_2: the Chigwell Viking E and I Pools. They have similar properties (Table 1c) 38^{o}API, avg. porosity = 0.13, avg. perm ~ 54 md, avg. water sat. = 0.39, avg depth ~1399m ,avg. initial pressure 8.5 MPa, and a CO_2 MMP = 13.8MPa.

The E pool has been on a CO_2 flood scheme since 2007. Since the start of injection, the oil production rate has increased to 100 m^3/day.

The I pool was previously HC flooded with ethane starting in 1999, CO_2 flooding initialized in 2006/2007. At the start of ethane injection the oil rate went from 20 to 140 m^3/day. After the start of CO_2 injection, the oil rate went from 20 to 90 m^3/day. In both cases the peak rate was followed by a sharp decline (Sproule, 2012). Straight CO_2 injection was switched to WAG when CO_2 breakthrough occurred. To date, primary recovery is 240,000 m^3, 100,000 m^3 from ethane injection and 80,000 m^3 from CO_2 injection (3.9% recovery factor for CO_2). Horizontal wells are currently be used to address geological heterogeneities based on past production history.

Pilots' Summary

The majority of the CO_2-EOR pilots are located in the Devonian carbonates (reef associated) where the bulk of the Alberta oil is located. The properties of these pools are tabulated in Table 1 with Table 1a containing the large carbonate reefs, Table 1b the smaller pinnacle reefs in the Zama area and Table 1c the sandstone hosted pools. Depths of the pools range from 1000 to 2600 meters, pressures from 7 to 23 MPa (with most of these initial pressures being close to their MMP), temperatures from 35 to 101^{0}C, API gravities from 26 to 41,viscosities from 3 to 8 centipose with one exception, initial oil saturations from 0.75 to 0.85, OOIP in the pools ranged from 394 to 1,488,000 x$10^3$$m^3$ with the smaller numbers being associated with the individual pinnacle reefs, reservoir thickness from 7 to 51 metres and porosities from 6 to 12%. The three largest oil pools are included: Pembina Cardium, Swan Hills and Redwater. Swan Hills and Red Water are large Devonian carbonate reefs siting on regional carbonate platforms which were the conduits for the oil emplacement. Notably, the largest oil pool, the Pembina Cardium is a sandstone, lacking in thickness (vertical dimension of the oil pool) compared to the carbonate reefs and consequently covering a large area relative to the other reservoirs and is not suitable for vertical floods.

Although most of the reefs have the necessary thickness for vertical floods, the vertical barriers inherent in the reef structures prevent using this technology in most cases, unless they are the smaller pinnacle reefs such as represented by those at Zama where often one well was sufficient to produce the pool on primary. The exception in the pilots, is the vertical flood at Redwater where attic oil is being targeted using the topography of the reef (based on 3D seismic) to define domed structures. CO_2 is injected at the top of the dome to form a gas cap and push the oil down to the ring of producers which are completed to the base of the domal structure. Even in these cases, oil is escaping out of the dome and being produced by existing outlier wells due to the complexity of the geology of the reefs.

Vertical floods require more CO_2 than horizontal floods as they fill up the reservoir from the top down, pushing the oil bank towards the bottom of the pool resulting in an HCPV of 1 compared to commercial horizontal floods which typically only inject 0.5 of an HCPV. Water does not have to be used for conformance in a vertical flood since the technique relies on a gravity stable displacement, the lighter CO_2 pushing the heavier oil downwards. This would also maximize CO_2 storage if this was a consideration. The vertical floods also can be interrupted without consequence, as long as the displacement front is stable. This is not true for horizontal floods as the CO_2 can escape to other parts of the reservoir when injection is interrupted. Some of the oil is bypassed due to the lower viscosity of the CO_2 and the time dependent solubility process in the oil. Consequently in horizontal floods, the WAG process is commonly used where water is injected to help divert the CO_2 to parts of the geological matrix which would have been bypassed otherwise. However, this results in more water being produced along with the oil at the production wells, even though it reduces the CO_2 production. Water handling can add significantly to the costs of the operation. For example in the horizontal carbonate flood pilots, the cumulative water produced ranged from a WOR of 8 to 36 m^3 water per bbl of oil produced where large amounts of cumulative water (> 68%) were injected relative to CO_2 injected. In vertical floods where no water is injected, water production would be expected to be much smaller. The exception to this was the vertical flood at Redwater which had a cumulative WOR to date of 27m^3 of water per bbl of oil. This can be explained by the strong aquifer support for the Redwater oil pool.

One of the biggest issues in the design of the pilots is the unknown local geological heterogeneities even though valuable experience has been gained from previous operations. Most of the pools have already undergone primary and secondary recovery (waterflood) and some have undergone tertiary recovery (HC miscible floods). This experience has not proven sufficient enough to rigorously understand the CO_2 flow paths in these reservoirs. Although, the injected CO_2 flow paths are predicted from the waterflood response, it appears that in some cases the CO_2 flow paths are unique based on 3D seismic.

Several of the piloted reservoirs had previously undergone a HC miscible flood which stranded some of these light hydrocarbons. In two cases, Swan Hills and Judy Creek, the pilot was designed to evaluate the recovery of both the oil and the previously injected hydrocarbons, and found to recover significant quantities of both relative to the oil produced. In the case of Judy Creek, the section chosen to operate the pilot was in an area where the previous HC flood had bypassed.

The purpose of the pilots was to evaluate the opportunity of pursuing CO_2 miscible floods as a follow-up strategy to historical recovery as in most cases over 50% of the oil still remained in the pools and aging infrastructure could be utilized (e.g. wells, pipelines, gas plants). Two technical questions need to be answered from the pilot. The first is to decide if the pilot was a technical success and the second is to be able to extrapolate the results of the pilot to the whole pool with confidence. In most cases, the second goal was more difficult, as the pilot was in a restricted portion of the reservoir and the results are difficult to extrapolate to the whole pool with certainty due to geological heterogeneity. This is quite evident in the Zama reefs case where 5 pinnacles were flooded with quite different responses. As there are hundreds of pinnacle reefs in the Zama area, it is difficult to evaluate the total potential increase in reserves due to CO_2 floods, even if only focusing on a technical basis.

Pilot well spacing varied from 40 to 80 acres, for the most part, utilizing existing vertical pattern wells for the producers and often drilling a new injector. In comparison to the U.S., commercial EOR projects well spacing commonly ranges from 10 to 40 acres with pilots being spaced as closely as 3 acres. Admittedly, the geology of the reservoirs is different in Canada, but even so this suggests that a case for infill drilling exists if these pilots ever expanded to a commercial stage.

The performance of pilots is often displayed as Recovery Factor (RF) versus HCPV of CO_2 injected (Figure 16) where HCPV represents the original pore volume occupied by the oil in the pool. The RF directly depends on the amount of oil produced during the CO_2-EOR phase. The Remaining Oil In Place (ROIP) at the startup of the CO_2-EOR phase can be calculated if the cumulative oil produced is known at any RF value. The value of the HCPV can also be calculated in a similar manner if the amount of CO_2 injected is known at any HCPV fraction.

Pilots should be designed to inject sufficient CO_2 to reach the decline curve stage in a reasonable amount of time by adjusting the pilot well spacing appropriately. However, most pilots injected approximately 15% HCPV of CO_2, a condition where the rate of oil is still rising (Figure 16). Consequently, it is very difficult to predict full field economics because the peak recovery rate has not been reached. Peak recovery rate and the decline curve can only be predicted through reservoir simulation which is fraught with large uncertainties. Rather a simple method based on analogues should be used similar to that proposed by Lake and Walsh. This will be discussed in more detail later.

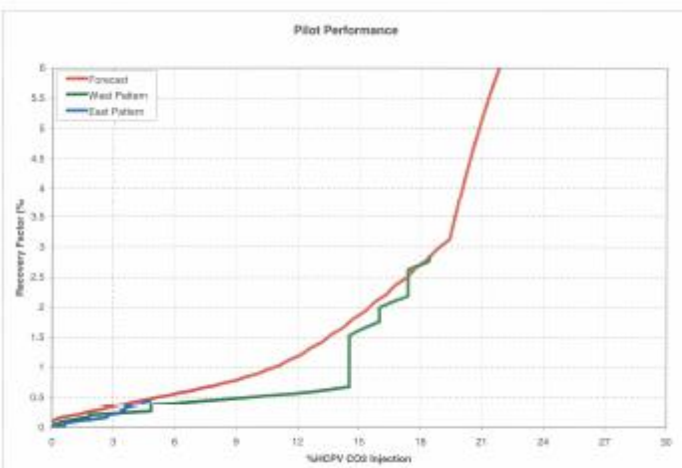

Figure 16: CO_2 pilot performance for South Swan Hills Beaverhill Lake A pool

In a CO_2 flood, the Voidage Replacement Ratio (VRR) will be high as the reservoir is brought up to the MMP and then will fall back towards one as production ensues, reaching unity at the end of the flood during the decline period when injection is reduced and the wells continue to produce as shown for the Joffre Viking (Figure 17). This was monitored for all of the pilots.

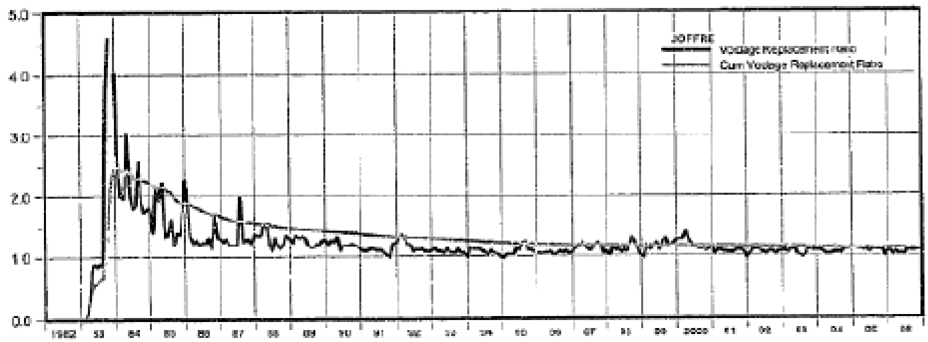

Figure 17: Joffre Viking – CO_2 flood voidage replacement ratio (Sproule, 2012)

Most of the pilots were considered a technical success as the ability to inject CO_2 at significant rates accompanied by enhanced oil recovery was demonstrated. Based on production data for the pilots, the CO_2 gross utilization factor ranged from 0.24 to 2.35 tonnes (4.4 to 38 mcf) of CO_2 injected per bbl of oil produced. Clearly the higher number is unsustainable but this reflects a snapshot in time where the HCPV of CO_2 injected is often less than 0.2 and the rate of oil production is still increasing. The issue for most of these pilots is the expense of trucking CO_2 into the pilot or the limited quantities available from the gas plant, the cost of this CO_2 exceeding $100/tonne. Consequently, the strategy for these pilots is to demonstrate that they can operate a CO_2 flood successfully and produce significant quantities of incremental oil without reaching maximum production rates. Reservoir models are used to extrapolate the production to maximum rates, predict the time when that occurs and then predict the decline curve. The largest uncertainties in this approach arise from predicting the maximum production rates and the time at which it occurs. If the pilots were run to an HCPV to reach the decline cure, then the predictions would be much more reliable.

Asphaltene and wax depositions problems were encountered to some degree in most of the pilots in the wells, production lines and separators associated with the depressurization of the produced fluids and loss of CO_2. These were addressed successfully by chemical drip and batch treatments by oilfield chemical companies but added significantly to the expense of oil production. This problem was not encountered during HC miscible floods. Corrosion from the acidic nature of dissolved CO_2 and mineral scaling due to pressure drops were also noted and remediated.

The commercial CO_2-EOR projects in Alberta are all in the Viking sandstone and were successful because of a nearby cheap source of relatively pure CO_2. If such a source existed for the Pembina Cardium sandstone, similar development would have occurred in the better portion of the reservoir. The only other commercial CO_2 – EOR project in Canada is located at Weyburn, Saskatchewan. However, Weyburn is not typical of the large carbonate reefs in Alberta. It was only through the opportunity of the use of horizontal wells, a cheap source of CO_2, the support of the Saskatchewan government and the rapid rise in the price of oil that made it a success (see discussion of this later in the report). On the technical side, horizontal wells were not part of any of the Alberta pilots except for one well in Zama; and the tertiary recovery in the Swan Hills area was through HC miscible floods because of the cheap source of solution gas being produced from the reefs during primary and waterfloods, an opportunity not available for Weyburn.

In most cases, there are no technical barriers why the results of the pilots wouldn't support commercial operations if a reasonable price for CO_2 could be obtained. The only exception appears to be the Enchant Arcs pool but this may be due to the low HCPV flooded (< 6%) and the unconfined nature of the pilot injector. Later in the report, CO_2 prices at the field gate are discussed. A price of approximately $2/mcf for

CO_2 delivered at the field gate at pressure would have revitalized interest in CO_2-EOR five years ago, but with the explosion in unconventional resource exploitation, other incentives may be needed (Baker et al., 2012).

Overcoming the Barriers to Commercial CO_2-EOR in Alberta, Canada
Part II: CO_2 – EOR Barrier and Opportunity Analysis

This section summarizes the opinions of 25 organizations that were interviewed on the importance and solutions to overcoming the 6 barriers to the practice of commercial CO_2 – EOR in Alberta. Sometimes their opinions differed and in such cases they have been recorded in this report. Finally, based on these interviews, a number of opportunities have been identified.

BARRIER 1: RESERVOIR CHARACTERISTICS AND PRODUCTION HISTORY

Some have suggested that the majority of Alberta's oil reservoirs are less ideal for CO_2 -EOR, due in part to certain reservoir characteristics and production history. What are the characteristics of Alberta reservoirs that would make them attractive for CO_2 – EOR?

A. Review

Alberta has a wide variety of reservoirs with characteristics and conditions that suggest there are some good CO_2-EOR candidates. Many of the better pools have undergone primary depletion and various degrees of secondary and tertiary depletion strategies. Even though there are still reservoirs with good CO_2-EOR potential in Alberta, we have not seen development of new CO_2 floods for over 20 years.

B. Reservoir Characteristics Important for CO_2-EOR

i. Database of information – ERCB has one of the most complete and accessible databases in the world containing detailed core and well data on all Alberta oil and gas pools as well as performance data spanning many years. Knowledge of fluid properties and reservoir properties is key in developing strategies around modeling, piloting and commercial EOR operations.

ii. Oil saturation and remaining reserves of oil – Ideally pools with greater than 50 million bbl remaining oil in place are desirable for CO_2-EOR targets. This is because CO_2-EOR at a commercial scale can be both capital and manpower intensive especially if the EOR scheme is integrated with the CO_2 supply and recycle operations.

iii. Miscibility – CO_2 floods work best if pressure can be maintained above miscibility pressure. Pressure can be affected by depth or presence of thief zones such as a gas cap or bottom water. Often water is used to re-pressure a reservoir up above miscibility pressures after primary depletion has reduced the pool pressure.

iv. Permeability and mobility of CO_2 – This is important to oil production, and can be detrimental to effective sweep using CO_2-EOR since CO_2 is much more mobile than oil or water. As a result, CO_2 may finger through and by-pass oil pay. CO_2 mobility can be controlled when used in conjunction with water. Also, foam and nanotechnology could be used to enhance the viscosity of CO_2 so that schemes could be operated at lower pressures and shallower depths. There have been no major advances in foam technology for 20 years – perhaps it is time to research this more for CO_2-EOR.

v. Asphaltene and wax – These precipitating in the reservoir, wellbore or pipelines can be a problem when using CO_2, so knowledge of the reservoir fluid characteristics is important in determining if CO_2-EOR is the best operating strategy. Alternatively, chemical treatments can suppress their formation.

vi. Geological and structural heterogeneities – These are a big unknown factor. Alberta reservoirs are both more heterogeneous and contain more natural fractures than their U.S. counterparts.

Heterogeneities need to be mapped in the target reservoir in order to optimize sweep and recovery. Low permeability zones are the biggest hurdle for CO_2-EOR. This can be overcome with infill wells, but this correspondingly increases capital and operating costs. History-matched models are very beneficial in alleviating much of the uncertainty around reservoir heterogeneities.

vii. Stacked reservoirs – These can be good for operating CCS sequestration in conjunction with CO_2-EOR when operating strategies require it.

viii. Gas Caps – For effective floods, the operator needs to keep the gas cap pressurized.

ix. Bottom Water – With bottom water drive, it is difficult to reach miscibility pressures.

x. Transition Zones and Residual Oil Zones (ROZs) – Planned water flood or nature's water sweep of an oil reservoir will leave behind oil saturated zones that are viable targets for follow-up CO_2-EOR. In both scenarios, remaining oil in place can exceed 50%. This is also discussed under New Oil.

C. Production and Performance History

A key factor in evaluating potential reservoirs for EOR is what has happened to the reservoir characteristics over the period of time it has been under primary or subsequent depletion. Also, reservoirs can be "prepped" for follow-up CO_2-EOR depending on the initial or secondary depletion strategy used.

i. Primary production – This gives a better understanding of the measured reservoir characteristics, history matching for enhanced model runs and thus more accurate prediction of follow-up depletion strategies.

ii. Waterflooding – This gives another level of understanding of the reservoir performance and potential:
   a. The reservoir may look homogeneous under primary production, but under water flood important heterogeneities may become more apparent.
   b. Water may be used to reduce relative permeability in order to control mobility of CO_2 in follow-up EOR schemes
   c. Water is also used to raise reservoir pressure to that required for CO_2 miscibility.

iii. Hydrocarbon (HC) flood - Performance curves from the flooded part of the pool should be applicable to the unflooded part of the pool.

iv. CO_2 Flood - CO_2 injection in tight reservoirs can overcome injectivity problems experienced by water injection since CO_2 is more mobile than water. Injectivity should increase along with relative permeability to gas as the CO_2 displaces the water.
   a. The CO_2 moves across primary production barriers to displace and recover more oil, but is so mobile that fingering can occur and some oil is still then bypassed.
   b. If CO_2 is used as a follow-up process to HC flooding, then incremental recovery is limited to 2.5% to 3% because CO_2 follows the HC path.
   c. In primary vs secondary vs tertiary use of CO_2, water can be used to temper the high mobility of the CO_2. Water-alternating-gas (WAG) processes can be used to move CO_2 around in the reservoir to improve recoveries by as much as 5 to10%. Tapered WAG processes, replacing WAG with CO_2 foam and simultaneous injection of water and gas (SWAG) further help to improve reservoir performance and oil recoveries.

D. Potential Candidate Reservoirs

In Alberta there are potentially many pool types to consider for CO_2-EOR: Beaverhill Lake (BHL) water flooded, BHL HC flooded, Pembina with a thief zone, Pembina without a thief zone, Redwater D3 with active aquifer support, gas cap or no gas cap etc. As part of this report, a number of operators and consultants were interviewed and gave the following variety of comments (some opposing) on the potential for EOR in Alberta. These reservoirs (and others) should be further evaluated and ranked for CO_2-EOR potential:

i. Swan Hills - Alberta's second biggest oil reservoir (Swan Hills) underwent miscible flood years ago making it less attractive, but is still has huge oil reserves. Swan Hills and East Pembina Nisku are good candidate reservoirs for EOR. A Swan Hills vertical flood is difficult because of geologic barriers. It may work in the top (attic) zone, but less well in lower zones. Same for Redwater with respect to vertical barriers.
   a. Smaller incremental recovery works in Swan Hills because of large size of reservoir plus existing infrastructure
   b. Oil/water contact in Swan Hills is low compared to Redwater

ii. Redwater is an amazing reservoir, > 50% recovery using primary and natures waterflood
   a. Redwater is an ideally situated reservoir as it is close to a CO_2 supply, although it is below miscibility pressure
   b. Redwater is a good candidate for both CCS and EOR
   c. Geology is still a big risk factor. Because there was no waterflood, geology is poorly known.
   d. Mobility ratio (relative permeability/viscosity) is also a concern because of low density of CO_2

iii. Sturgeon and Sturgeon South have 150 million barrels each remaining potential (with 5-10% incremental recovery expected). Sturgeon was never waterflooded and there is no source of CO_2 nearby.

iv. Devonian Nisku trend is a potential EOR target.

v. Duvernay has both tight oil and gas. The oil is Devonian, but is deeply located.

vi. Pembina Cardium is a sandstone reservoir with lots of parasequences similar to the Viking sandstone
   a. Cardium play is varied: The conventional Cardium has no conglomerate. There is big area in the middle of the play with a conglomerate thief zone and better sands under the conglomerate. Halo sands are tight.
   b. Tight Cardium has poor injectivity and poor sweep

vii. Clive has an open ended natural water drive and is not a good reservoir for EOR as there are miscibility issues. It is similar to Redwater in that sense.

viii. General comments:
   a. There is more confidence with the geological model in Pembina than with concerns of sweep efficiency. Targets should be zones with higher residual oil.
   b. Pools with aquifer support from regional aquifers (e.g. Redwater from the Cooking Lake aquifer) are difficult to pressure up for miscible operations.
   c. Rather than EOR, operators have been chasing the poorer edges (haloes) of pools using new technology (multistage fracing of horizontal wells)
   d. Need appropriately sized pool to match volumes of available CO_2 (~ 1000 tonnes/day). North of Fort Saskatchewan, pools are large and within trusts so hard to get access to them. Also have been HC flooded.
   e. Saskatchewan has better EOR potential than Alberta due to the nature of heavy oil resources and reservoir geology like Weyburn
   f. Tundra and Legacy are both having success with water flooding tight oil in Saskatchewan.

E. **Discussion:**
   i. Follow-up evaluation study and short list ranking of Alberta potential EOR pools for CO_2-EOR potential is needed, based on known reservoir characteristics and production history (build on databases created in ERCB by Sproule, 2012 and in PTAC by Epic, 2006 studies).
   ii. Identification and evaluation of CO_2-EOR potential of residual oil zones (ROZs) in Alberta.
      a. The Alberta Geological Survey (AGS) (either internally or by an external contract) should review core/log data to determine where "residual oil zones" exist in Alberta and how large they are. Identification of gaps in core and log data can form the basis for future assessments if warranted.
      b. More study is required to map transition zones in Alberta that may be naturally good for CO_2 floods.
      c. There could be a lot of residual oil zones along the D-3 reef chain.
      d. There is a huge amount of trapped oil & gas in the "Golden Trend" (Bonnie Glen, Westerose D3) which has not undergone HC floods. This could be a target for ROZs.

BARRIER 2: COMPETING TECHNOLOGIES WITH CO_2 - EOR

Classically, exploitation of oil and gas reservoirs was with vertical wells and fracing, technologies which are over 50 years old. However with the development of horizontal drilling and steering while drilling, the deeper oil sands were opened up with SAGD technology, evolving from the AOSTA UTF (Underground Test Facility) where any company could "plug and play". Even in the case of Weyburn, it was horizontal well technology which allowed PanCanadian to devise a scheme which could go after the oil in the lower permeability Marly zone which had been by passed during the waterflood. This was before the development of multistage fracing in horizontal wells. Although not realized at the time, the technology was heading towards a regime which tended to neutralize reservoir heterogeneity in exploitation of oil and gas pools. Furthermore when multistage fracing in horizontal wells was introduced, the oil and gas industry had found a regime in which no reservoir was too tight for oil and gas production, effectively allowing oil and gas source rocks to be developed as profitable producing oil and gas reservoirs. The only limitation is the economics and the effect on the environment. CO_2-EOR has to compete with technologies such as improvements in horizontal wells with multistage fracing, infill drilling, waterflooding, and other EOR solvents displacing CO_2-EOR. Horizontal wells with multistage fracing may deliver faster and better return on investment. Is there an opportunity to transition to CO_2 – EOR at a later stage using these new technologies?

A. **Solvent Floods (basically hydrocarbon, nitrogen or CO_2)**:
   i. Solvents require adequate reservoir pressure for miscibility. Their MMP can be higher or lower than CO_2 depending on the percent of the heavier components in HC floods.
   ii. The recovery factor is thought to be higher with CO_2 than with HC floods.
   iii. In some pools, hydrocarbon or H_2S floods work better than CO_2. Nitrogen does not work well.

B. **Chemical Floods**
   i. Can be done on smaller scale than CO_2-EOR floods. CO_2 needs more infrastructure (capital) and is more man-power and monitoring intensive (operating costs).
   ii. Fields without a nearby CO_2 source are looking at chemical EOR as it can be done remotely, with smaller infrastructure and lower cost.

C. **Water Floods**:
   i. Water floods don't work as well as CO_2 floods in low permeability reservoirs. Using a miscible flood, like CO_2, can avoid water blocking of tight sands.

ii. Can't do a water flood in a single well pool (pinnacles)
iii. Mobility is not as much an issue for water floods as it is for CO_2, where CO_2 can finger through and by-pass oil pay.
iv. Conventional water floods demonstrate conformance, but high tech horizontal wells and multistage fracing may provide similar conformance for CO_2 floods.
v. Water is becoming scarce for water floods (particularly in the south) and water-swelling clays can be a problem in some areas. There may be potential for CO_2 to be used in place of water flooding in these areas.

D. **SAGD**:
i. SAGD is looking for a gas that is lighter than steam that will insulate the steam chamber (this could be an economic use of CO_2), but it needs piloting.

E. **CO_2 Huff and Puff**:
i. There may be more follow-up opportunities in tight oil where CO_2 (due to its mobility) may be lost in more permeable and fractured reservoirs.
ii. Once you get channeling when flooding a fractured reservoir, production is compromised; therefore CO_2 huff and puff may be best alternative.
iii. Huff and puff has shown some success as a secondary recovery method in unconsolidated, highly permeable oil sands reservoirs using the CHOPS (Cold Heavy Oil Production with Sand) process.
iv. Generally economic return in tight reservoirs is lower than in permeable ones, so there is greater potential for economic return with huff and puff in these reservoirs.
v. Huff and puff does not need to be done at miscible pressures to work
vi. Huff and puff is typically used to establish communication in tight reservoirs(want communication in 2 or 3 months), then followed with directional flood
vii. Two to 3 % recovery is typical using huff and puff.

F. **Horizontal vs Vertical Floods**
i. Operators can be far more flexible on vertical flood as the flood front can be maintained as long as the production rate is the same as the injection rate (can turn flood on or off). Horizontal floods need continuous injection to maintain flood front.

G. **Horizontal Well Technology in conventional oil plays**:
i. Technology has improved considerably in the last 20 years. Long-reach distances, exceeding 2km, are now achievable which has opened-up previously uneconomic reserves for primary recovery. Also, a greater percentage of new drill horizontals are being used. This has rejuvenated interest in primary recovery and EOR has been put back on the shelf.
ii. Secondary/tertiary CO_2-EOR using horizontal wells is still relatively new and more field testing would be beneficial.
iii. In conventional (permeable) oil plays, the orientation of horizontal wells to permeability trends which are the most beneficial for primary production may be detrimental to the success of follow-up CO_2-EOR (i.e. poor sweep efficiency).
iv. Rapid decline and low ultimate recovery from unconventional methods may mean EOR will become attractive again. There is still a lot of oil in place that could be recoverable after unconventional primary methods are finished.
v. Multistage fracing is transitioning into a large scale "manufacturing" mode like oil sands. The strategy is to drill a horizontal well completed with multistage fracing in a tight reservoir and

then produce it on primary. The decline curves are very steep, partly due to healing of the fractures. This is countered by refracing the well until the peak production drops substantially from the previous fracing. Then a new horizontal is drilled at a predetermined spacing and multistaged fraced; and so on. EOR may need to follow suit.

H. Discussion

i. Technical review and analysis of existing studies (e.g. ERCB-Sproule 2012) and pilot reports could be potentially a next phase of this report, including a further technical review on narrowing down pools where CO_2 will be easily miscible, having regard for bottom water, secondary water flooding and other pressure (miscibility) factors.

ii. Huff and puff is not a favored technology as oil and gas companies tend to focus on time duration of the project which reduces to processing rate (Need to ramp up oil production quickly). However, in low permeability reservoirs such as the oil sands where the oil is immobile, a drive process cannot be initiated because the wells lack communication due to the bitumen blocking the native permeability. Consequently, steam is used to "melt" the oil in a cyclic huff and puff process until the communication is established and then steam drive is initiated. Husky has found this process successful as a follow up process in their CHOPs heavy oil reservoirs using both HC gases and CO_2, but they favor CO_2. This heavy oil can be as heavy as API 12^o and even though it is an immiscible flood, the benefits are thought to outweigh the costs. This is uncharted territory for CO_2-EOR as most screening procedures have a cutoff of API of 22^o. This eliminates oils from API 21 and lower for consideration for CO_2–EOR. Huff and puff needs further testing in a range of different reservoir conditions.

iii. More studies are required to assess sweep efficiency with respect to orientation of horizontal wells relative to permeability trends and use of CO_2 floods.

BARRIER 3: NEW OIL RESERVES

Since the development of Weyburn, the advancement in technologies in horizontal drilling and multistage fracing have opened up new opportunities in tight oil and gas which were never envisioned before. These technologies have brought gas prices tumbling and soon oil prices may follow. New projects in oil and gas companies have to compete with each other. Focus is towards quick returns and low risk both which make CO_2–EOR a "hard sell". The success of primary production of tight oil and gas has temporarily put CO_2-EOR on a "back bench". The emergence of commercial tight oil recovery (e.g. Bakken) has significantly increased total oil reserves lessening the need for tertiary oil recovery. Is there an opportunity to transition to CO_2 – EOR after primary recovery?

A. **Primary recovery:**

Primary recovery of new unconventional oil reserves (oil and gas liquids) is more economically attractive than EOR, however decline curves are very steep and recovery represents only 2-3% of oil in place. This leaves a lot of oil still in the ground for secondary through quaternary recovery methods like CO_2-EOR (it is important not to sterilize this remaining oil in place because of poor design or methods used for primary recovery).

i. Swan Hills has tight oil in lagoonal areas and rims; 3 billion bbls in platform.

ii. Pembina and Duvernay have tight oil, Montenay has oil shales.

iii. Cardium has bioturbated sands which are tight and can't be waterflooded.

iv. Bakken

   a. CO_2 enhanced recovery from the Bakken should be looked at.

   b. Bakken fracs aren't permanent resulting in poor recovery.

c. Steep decline curves are found for primary production (300 bbl/day to 10 bbl/d = base plateau rate).
d. There is an opportunity for EOR tight well spacing of several hundred metres

v. Residual Oil Zones (ROZs) – Steve Meltzer in U.S. has identified 9-13 potential projects where natural water sweep of an oil reservoir has occurred leaving behind high residual oil saturated transition zones (ROZs) that were previously thought to be uneconomic. These are ROZs can have saturations exceeding 40% oil and are immobile to waterfloods; and they are currently the target of "unconventional" CO_2-EOR after the mobile zones have been swept by conventional CO_2-EOR . He explains their existence by tectonic activity after the emplacement of the oil and the change in the hydrodynamics of the basin. For example, if the basin undergoes tilting after the formation of the oil reservoir, the hydrodynamics of the basin will change and under the new hydrogeology regime, the recently emplaced oil reservoir may be waterflooded through natural processes creating a large residual oil zone (ROZ) beneath the mobile oil reservoir. If "natures" waterflood goes to completion, the oil reservoir may disappear leaving behind a detached ROZ. The presence of large transition zones in conventional oil reservoirs suggest that this process is working over geologic time and that detached ROZs could exist. They would be bypassed in traditional exploration even though the logs may have indicated oil saturation, because a drill stem test would produce no oil. A knowledge of the history of the hydrodynamics of the basin would allow prediction of where such detached zones might occur (e.g. the Golden reef trend in Alberta). They would represent primary targets for CO_2-EOR.

vi. CO_2 Flood or huff and puff looks like a viable EOR method for ROZs.
a. Alberta potential sites have not been identified yet and may require additional drilling to get necessary core and log data.
b. Quality of the ERCB data repository makes ROZs more attractive than in the U.S. where the data is not easily found. Potential sites of interest are:
- Leduc, Rimbey, Golden trend
- Gas caps are after the ice age and could be ROZs
- Tight oil associated with halo areas of reef (i.e. platform as well as internal lagoons may have residual zones)
- Tight oil exploration in front of reefs in regional platforms (=regional aquifers)
- Along D3 reef zones

B. **Economic payback:**

i. High rate and rapid payback are attractive for primary recovery in new conventional and unconventional (tight) oil plays. Although primary recovery has a faster return on investment, it is a less efficient (lower recovery) oil recovery system than CO_2-EOR.

ii. High up-front cost and delayed payback make CO_2-EOR less attractive than unconventional primary recovery. It will take 2-4 years for CO_2 flood schemes to start delivering a profit.

iii. Large volumes of unconventional oil coming on the market have depressed oil prices which makes it hard to make an economic case for CO_2-EOR.

C. **Hydraulic fracturing in unconventional (tight) primary production oil plays**:

i. Multistage fracing of horizontal wells has made technical advances that give access to previously uneconomic unconventional (tight) oil reserves. Primary production using this technology has put CO_2-EOR on the back-burner from an economic perspective. This is due in part to the high rate, quick payback of primary production versus the slower rate longer payback of CO_2-EOR.

ii. CO_2-EOR incentives are being considered because of delayed payback to compete with unconventional oil production which already has incentives in place.
iii. Massive fracing in unconventional plays open communication pathways that may be detrimental to CO_2-EOR floods. The mobility control required for CO_2-EOR is not possible in fractured reservoirs.
iv. In unconventional (tight) oil plays, the horizontal well orientation optimal for hydraulic fracturing for primary recovery may be detrimental for CO_2-EOR flooding, because breakthrough and channeling along the permeability trend can significantly reduce sweep and ultimate recovery by follow-up CO_2 flood. Drilling across the natural fracture trend without hydraulic fracturing may work better. Operating CO_2-EOR as huff and puff may also overcome this problem.
v. Primary production fracture communication between adjacent fraced horizontal wells further reduces sweep efficiency for secondary CO_2 flooding. Fracing methods (such as zipper fracs), spacing between horizontal wells, orientation and choosing the best well for injection all need to be examined to see if they help or hinder ultimate recovery having regard for net present value/rate of return (ROR) economics. (Need to consider secondary recovery before going too far down primary path with unconventional methods -a resource conservation and ultimate recovery consideration – although some say this is not an issue).

D. Enhanced Recovery:

i. Only a small % of tight oil plays can be used for CO_2-EOR
ii. Surge Energy is testing water flood in tight oil. CH_4 is also being tested
iii. CO_2-EOR was very big from ~2005-2009. In 2009 the economic downturn reduced the interest in CO_2-EOR and tight oil became the new company priority. As time goes on the expertise gained from 2005-2009 is being lost.
iv. Tight oil has a fast decline so may not last long. Companies may go back to the "big" plays for enhanced recovery, but it will get harder to go back to them as infrastructure is closed in and saturation decreases

E. Discussion:

i. Horizontal wells and multistage fracing only produce 3 to 10% of the OOIP, and so follow up technologies are being investigated. There is a wide permeability range for tight oils, so a secondary process which might work in one reservoir may not work in another. In the tighter reservoirs, waterflooding may not be efficient due to water blocking at the lower permeabilities. This opens up secondary processes to gas flooding, including CO_2. This is currently being investigated in two theoretical and lab studies, one by PCOR and one by AITF, and will be piloted in the future. More pilots are needed to understand how to undertake primary development of tight oil in order to optimize oil production for secondary and tertiary recovery methods.
ii. More modeling and field studies are required to optimize orientation of horizontal wells for ultimate recovery of unconventional oil plays using CO_2-EOR flood versus huff and puff.
iii. Quality of the ERCB data repository makes ROZs in Alberta potentially more attractive than in the U.S. where the data is not as complete or accessible. Alberta potential sites have not been identified yet and will require additional drilling to get necessary core and log data for detailed characterization.

BARRIER 4: CO_2 SUPPLY FOR CO_2 - EOR

Ninety-five percent plus purity CO_2 is needed for EOR. Currently, CO_2 supply cost (capture and transportation infrastructure) is too high in Alberta. In Canada, commercial CO_2-EOR projects are dependent on negotiating a secure supply of CO_2 at a reasonable cost. Although the supply of CO_2 is potentially large, capture costs of a pure stream of CO_2 from waste streams are quite variable. The cheapest streams are those from chemical plants which only have to be dehydrated and brought to pressure for pipelining, nominally $20/tonne ($1.08/mcf) of CO_2. By far the bulk of the CO_2 waste streams are dilute CO_2 from combustion and cost in the range of $100/tonne ($5.39/mcf) for capture (including dehydration and compression). CO_2-EOR projects, on the other can nominally afford CO_2 in the range of $20 to $40/tonne (~$1 to $2/mcf) depending on the reservoir. Therein lies the dilemma or the so called economic gap. What is an acceptable price for CO_2 supply in order to implement CO_2 – EOR projects?

A. Supply Price of CO_2 seems to be the biggest single barrier.

i. The supply price of CO_2 can be broken down into three main sources:
   a) CO_2 from natural sources can cost as little as $5/tonne ($0.27/mcf) but there is no natural source in Alberta. Compression and transportation costs to get natural CO_2 from U.S. geologic sources to Alberta are substantial.
   b) There are small quantities of pure CO_2 available at $40/tonne ($2.16/mcf) from industrial sources (hydrogen/fertilizer/gas plants)
   c) The bulk of CO_2 comes from combustion sources at much higher cost ($120/tonne, $6.47/mcf). CO_2 costs at $120/tonne are made up of: 80% capture and compression, 15% transportation, 5% injection. Recycle cost still needs to be added in and is in the range of an additional $13 to $17/tonne ($0.70 to $0.92/mcf).

ii. What is an affordable price for CO_2-EOR? This can vary between $20 and $80/tonne ($1.08 - $4.31/mcf), depending on the nature of the EOR project. CHOPS process is competitive at $80/tonne ($4.31/mcf) CO_2, but most other CO_2 EOR projects affordable price ranges from $20/tonne to $45/tonne ($1.10/mcf – $2.40/mcf). Generally, oil at $90/bbl will support a CO_2 supply cost of $37/tonne ($2/mcf).

B. Factors affecting asking price.

i. At existing locations CO_2 is considered a waste stream until someone shows interest in it, at which point a “utility mentality” is often applied to CO_2 supply (cost plus). Currently this puts the asking price at $75-$95/tonne ($4.05 - $5.12/mcf). Utility mentality of cost plus will kill any project and therefore this approach (mindset) needs to be changed for CO_2-EOR to be viable.

ii. Source priced at $40/tonne ($2.16/mcf) - The cheaper industrial sources of CO_2 do not provide enough reliability and volume of CO_2 for commercial scale CO_2-EOR.

iii. Source priced at $95/tonne ($5.12/mcf) - Large scale, high cost/tonne capture and compression facilities are needed to capture more expensive CO_2 from combustion sources. Such projects would likely be undertaken by large CO_2 emitters as part of a GHG emissions reduction project integrated in with existing revenue- producing operations. They may even be integrated into onsite operations eliminating the need for long supply pipelines.

iv. Transportation (pipeline) costs at $18/tonne ($0.97/mcf) to move CO_2 from source to EOR project areas (several hundred kilometers away). If there are existing pipelines, they were not designed to carry CO_2 and would require expensive retrofits (liners, seals, valves). New pipelines would likely be more economic, but still expensive.

v. CO_2 injection priced a $6/tonne ($0.32/mcf) - Injection site operating costs associated with wells is small compared to CO_2 capture and transportation costs. Most existing production wells can be retro-fitted for CO_2 injection at minimal cost.

vi. Recycling priced at $17/tonne ($0.92/mcf)- Recovery and reinjection of CO_2 during operations is an additional cost, but off-sets some (project specific) volumes of make-up gas from more expensive combustion sources. This may or may not be an incremental cost depending on whether recycle is integrated into the CO_2 capture component.

C. Economics:

i. CO_2-EOR operations have large initial capital investment with a long capital recovery period. Small companies do not have the money to undertake large scale CO_2 capture and injection for EOR. Large companies have a broader resource base with more attractive targets for their budget dollars than CO_2 - EOR.

ii. Infill well drilling is currently cheaper than EOR.

iii. CO_2-EOR has higher risk and lower reward than other opportunities.

D. Case Examples:

The two Canadian commercial examples of CO_2 – EOR projects are Weyburn (commencing in 2000) operated by PanCanadian (now Cenovus) and Joffre Viking(commencing in 1982) now operated by Penn West. Contrasting the two pools, the Weyburn pool was huge, exceeding a billion bbl OOIP, but the CO_2 source was 300 km away while the Vikor pool was small (around 50 million bbl) but the source was nearby. Both CO_2 waste steams were very high in CO_2. Joffre was able to start because of partial government funding of the pilots through AOSTRA. Weyburn relied on the nearby Shell Midale pilot to evaluate Weyburn. PanCanadian evaluated 6 sources of CO_2 for Weyburn: Syncrude/Suncor, Saskatchewan Power, Dakota Coal Gasification, natural CO_2 reservoirs in the U.S., Wabamun power plants and the Exxon La Barge gas processing plant. The Dakota gas plant was a good fit, as it had a pure waste stream of $CO_{2,}$ and it was losing it financial support from the U.S. government and needed to find additional sources of income. However, the gas plant had to find the finances and build a 300 km CO_2 pipeline from North Dakota to Weyburn to supply the CO_2. They were successful via a loan from the U.S. government. The Saskatchewan government wanted the project (as it would create 1200 jobs) and agreed to lighter front end royalties to help accelerate the payoff of the capital. PanCanadian shared all the project information with the Saskatchewan government except for their reserve numbers. The economics were based on $20 -$25 oil. The federal government did not offer funding. One attraction was that PanCanadian could book the amount of oil that they expected from the CO_2 - EOR flood as a reserve rather than have a finding cost. The original forecasted ROR for Weyburn was 20%. CO_2 credits were split between PanCanadian and Dakota Gasification as was the risk. Similar size oil pools to Weyburn exist in Alberta in Swan Hills, the Pembina Cardium and Redwater. Both the Pembina Cardium and Swan Hills are not near a large relatively pure CO_2 source, similar to Weyburn in this respect. However, Swan Hills has already undergone HC miscible flooding and the Pembina Cardium is a difficult reservoir to flood due to its large area and relative thinness. Redwater is more attractive but its shallow depth does not allow for a miscible CO2 flood. Consequently, new commercial CO_2 - EOR projects were not justified in Alberta at the time Weyburn started its miscible flood in Saskatchewan.

Over the past two years, two other commercial projects have been considered. Pioneer failed because TransAlta, a utility couldn't find an oil and gas company to purchase their CO_2 for CO_2 - EOR because they couldn't agree on a price and a guaranteed uptake of the CO_2 over the long term. On the other hand, Enhance Energy pursued an integrated solution where they own the CO_2, the pipeline and the CO_2 – EOR reservoir (Clive). Their success isn't guaranteed but the project will reach the oil production stage.

E. Discussion:

i. Increasing the CO_2 GHG tax to incent more recovery of CO_2 from combustion sources will likely only result in that cost being passed along as an increased asking price for the CO_2.
ii. Reducing the CO_2 GHG tax or other royalties and taxes for the combustions source owners would only work if the CO_2 – EOR projects are truly integrated with the utilities capture of CO_2.
iii. Royalty incentives and tax breaks for the purchaser of CO_2 may be a better solution than more tax on source emissions. More regulation may be needed where the CO_2 supplier (emitter) and purchaser are the same.
iv. Government participation (financially) in large integrated CO_2 capture and transportation projects could keep the price of CO_2 down for purchasers of CO_2, but again only if the "utility mentality" is regulated.
v. Government may need to step in to broker CO_2 by purchasing it from suppliers and selling it to users to maintain reasonable pricing.
vi. Government should find a way to provide small and large operators with equal opportunity to develop EOR.

BARRIER 5: INTEGRATION OF CO_2 – EOR & CCS

How can CCS have a positive influence on CO_2 – EOR? What are the additional requirements to convert a CO_2 – EOR project to CCS and the impact that these requirements would have on a CO_2 – EOR project?

A. CCS are large scale projects:

i. CO_2 capture:
   a) 95% purity is desired to minimize compression and pipeline requirements for injection and to keep miscibility pressure low in CO_2-EOR applications.
   b) The energy intensive process to capture CO_2 from combustion sources further increases overall CO_2 emissions.
   c) Capture is expensive (energy, infrastructure).
ii. Pipeline from source to sink – Existing pipelines may not be structurally sound due to aging or may not have adequate design.
iii. Compression and injection infrastructure is costly as special metallurgy and design is required.
iv. Geologic Storage – It needs to be large enough to handle the rate and volume of CO_2 being captured and provide secure containment as well as reproduce the CO_2 for EOR at desired purity, pressure, rate and volume.
v. Measurement and reporting is onerous.

B. CO_2-EOR are large scale projects:

i. Pipeline from source to sink – Existing pipelines may not be structurally sound due to aging or may not have adequate design. In Alberta CO_2 sources and sinks are often far apart which increases cost.
ii. CO_2 pipelines are needed, but who should pay the cost, the CO_2 supplier or the buyer? Can it be shared? Who gets the CO_2 credits? Is there a benefit from the operator owning both CO_2 capture unit and EOR field?

iii. CO_2 recycle plant is needed to clean up CO_2 from storage as well as produced CO_2 (this ideally would be the CCS capture plant).
iv. Electrical power generation might be required on site for power for processes.
v. Geologic storage buffer (ideally this would be the CCS geological sink) may need to be in place. CO_2 demand is greatest at beginning (phase 1) of EOR project as reservoir needs to be "charged-up". Then recycled CO_2 can be used for subsequent phases. CCS is best done at the end of an EOR project from a NPV cost basis.
vi. Measurement and reporting is a lot more onerous (manpower and equipment cost) than other oil recovery schemes (need to simplify this)

C. Existing Incentive Projects:

i. Enhance's pipeline project, for the most part, looks like good business with two possible exceptions.
   a) The Clive pool, which is the initial target, has active bottom water and can't be economically blown down to reproduce injected CO_2 because of cleanup and cost especially with aquifer support.
   b) Enhance is building a new pipeline using all new piping. Existing infrastructure may have provided a better value. (Note: some say old pipeline systems not structurally adequate to carry CO_2).
ii. Capture cost for Pioneer project was too high, such that the Pioneer project did not move forward.
iii. Shell is committed to 51% of CO_2 being injected in basal aquifer for 10 years.
   a) Shell Quest should be shipping 92-98% quality CO_2 to EOR rather than storing in the basal Cambrian aquifer.

D. General CCS Project Considerations:

i. Use technologies to reduce CO_2 emissions, that are profitable, rather than creating cheaper ways to produce pure CO_2:
   a) Nuclear applications could be used to offset fossil fuels where possible to lower emissions (e.g for producing steam for oil sands – issue is size as steam can only be transported 15 km. Challenge is up front capital.).
   b) Focus should be on ecoefficent technologies – cars etc. where efficiency goes from 30 to 70%.
   c) Don't spend money on CCS alone – too costly – look at ways to replace high emission sources with lower emission sources. (eg. Replace hydrocarbon-fired steam generators with nuclear units).
ii. Final pressure for storage should be allowed to be above reservoir pressure (seek this from regulators).
iii. Saline aquifers will never economically reproduce the CO_2 because it has now become hydrated and is at low pressure.
iv. CCS is the low-cost option compared to wind and solar. A lot of lower cost options cannot be scaled up e.g. biochar – can't scale up economically.
v. Under current market conditions, reinjecting CO_2 from CCS for CO_2-EOR would be of marginal value.
vi. Reprocessing CO_2 and recycling incurs a high cost.

E. CCS/CO_2-EOR Integrated Project:

i. EOR first then CCS – This needs to consider upfront integration at the beginning.

ii. Demand for CO_2 volumes for EOR is small compared to CO_2 sources. Couple CO_2-EOR with storage. Only dirty CO_2 and CO_2 not needed for EOR should be sent for sequestration. CO_2-EOR provides the infrastructure and geological sink for storage.
iii. Makes sense to kick start CCS with EOR as it will reduce cost of storage from $100/tonne to $70/tonne.
iv. When CO_2 capture systems come online there is a large volume of CO_2 at once. CO_2-EOR demand for CO_2 ramps up and changes over time, therefore need CCS in place to store the CO_2 (as a load leveler) until EOR can take it (exactly what the Heartland Area Redwater Project (HARP) was intended to do). It is suggested that CO_2-EOR schemes have a saline aquifer nearby that could be used to store any of the CO_2 that can't be used for CO_2-EOR (CCS would act as a buffer for the CO_2 supply).
v. Finish with CCS at the end of the scheme after completion of the CO_2-EOR flood.
vi. When considering CCS as a follow-up to EOR, keep EOR economics separate, then tack on incremental economics of CCS to determine its viability as a follow-up process (this will be difficult if the projects need to be integrated from the beginning).
vii. EOR could leave sequestered in the EOR reservoir, 5-6 mcf of CO_2 per barrel of oil produced (20-30% of the gross CO_2 injected is sequestered at end of EOR project).

F. Discussion:

i. Incentives:
  a) There is strong argument for large integrated CCS CO_2-EOR schemes similar to that occurring for oil sands development. This will likely need government financial participation to kick-start.
  b) A complete change in economics is needed which CCS might provide.
  c) If CO_2 is still an emission/GHG concern, then CCS will continue.
  d) If government forces CCS (capture), then that could support a more attractive CO_2 supply price (we have to be careful though, that we don't force other sectors (electric power consumers) to shoulder an unfair portion of the economic burden for CCS or EOR).
  e) If Government is committed to CCS, then Government needs to help with building infrastructure for capture and transport.
  f) EOR need to lead the development, but CCS needs to be implemented.
  g) CCS is driver for EOR because EOR cannot compete with tight oil. However CCS requires appropriate policies.
  h) CO_2 sources are grandfathered for older plants and emissions not restricted. Only new plants fall under emission regulations.

ii. CO_2 Credits:
  a) CO_2 storage credits have to exceed cost of CO_2. If this is the case, then the CO_2 net cost (purchase cost – credits) will be negative.
  b) Who gets the CCS credits and how do you share them? Credits should not be given to the source but to the sink as they have the liability.
  c) Need to value credits over time when CO_2 is going in and out of reservoir. This reduces risk if CO_2-EOR is not performing and you can claim money for CO_2 storage. Currently, credits are only available in the future after CO_2 accounting is approved, so they are worthless as time is discounted.
  d) Credits are based on purchased and injected CO_2, but not on recycled CO_2 (how do you track the CO_2 that is actually captured in the reservoir)?

e) Credits for CO_2 – EOR should be calculated using a method proposed in a DOE/NETL report (2008). Compared to crude oil produced by primary or secondary waterflood, exclusion of CO_2 –EOR from being accepted as a CCS project is wrong. The price of oil produced by CO_2-EOR can be viewed as an offset for CCS. Kruuskraa and Ferguson (2008) used a simple methodology (DOE/NETL) to calculate the CO_2 offset for EOR based on the following example. Five to 6 Mcf (0.26 to 0.32 metric tonnes) of purchased CO_2, and 5 to 10 mcf (0.26 to 0.52 metric tonnes) of recycled CO_2 are used over a commercial CO_2-EOR process per barrel of oil. If all CO_2 produced is recycled, then purchased CO_2 = net CO_2 stored in the reservoir. One barrel of crude oil contains 0.42 tonnes of releasable CO_2 assuming that 3% of the produced and refined oil barrel remains as asphaltene or coke. Therefore the releasable CO_2 from EOR production is reduced from 0.42 tonnes/bbl oil to the difference (0.42 – 0.32) 0.10 tonnes bbl of oil. This makes the oil produced by CO_2 – EOR approximately 75% carbon free compared to crude oil produced by primary or waterflood methods. Adjustments need to be made for the additional CO_2 produced due to separation, compression and recycling as in any CCS calculation.

iii. Interesting concept:
Use the high quality, lower-cost CO_2 from natural CO_2 domes. Backfill the natural domes with the low-quality captured CO_2. The domes have already proven that they can store CO_2 securely.

BARRIER 6: UNITIZATION AND REGULATIONS

Unitization of Alberta's major oil fields is required to provide the integration and size necessary to make financing projects attractive, once a cheap supply of CO_2 is available. What can be done to make unitization more effective?

A. Regional Issues:

i. Unitization is a complex and difficult process. Companies argue over details of resource characterization and reservoir attributes. Competiveness often directs the positions of the land/lease owners who try to maximize their allocations. Companies are focused on the most reward and quick returns rather than the best strategy for the pool. We don't have a simple unitization process.
ii. Unitization could be an issue in the U.S. where there is more freehold than in Alberta. In Alberta, liability is likely to be biggest issue.
iii. If CO_2-EOR areas expand beyond existing defined pools, then unitization becomes more of an issue, since land ownership can be fragmented.
iv. Industry does not appear to see unitization as a stumbling block. Out of 1100 application schemes, only a handful go to an ERCB hearing.
v. Culture favoring unitization that existed in the past doesn't exist now. Unitization is less of a concern now compared to 20 years ago.

B. Reservoir – Pool Issues:

i. Unitization usually occurs during secondary recovery, typically a waterflood. Unitization is not needed for during primary production.
ii. Need to look at "whole reservoir" picture. What might be economical on the whole reservoir may not be economical for the pieces owned by different companies (fragmentation of oil fields is an issue).

iii. Works well in larger reservoirs, but even unitized owners have difficulty agreeing on operating strategy.
iv. Could be an issue for smaller companies that only own part of a pool that needs to unitize
v. Unitization can be an issue (theft of CO_2, "ring fence" impacts).
vi. Equity - Hold out leases/companies can cause issues when their wells lie adjacent to CO_2-EOR operations by producing additional oil, CO_2 or causing miscibility issues. CO_2-EOR operators need to know that they will be protected from "hold-outs" (need buffers around EOR schemes).

C. CO_2-EOR Issues:

i. EOR project needs much more management as it is labor intensive. This could complicate unitization agreements.
ii. Need to do water flood before EOR and water flooding requires some kind of joint venture agreement.
iii. A producing well adjacent to but not in the EOR unitization scheme can take the enhanced production from the EOR scheme as well as the CO_2. The CO_2 produced through this well would be vented and therefore the EOR operator incurs two penalties, loss of oil production and loss of CO_2 which could have been recycled or claimed as a credit.

D. Unitization in Existing Projects:

i. Both Midale and Weyburn were forced unitization. A workable situation has been achieved at Weyburn by openness, the ability to compromise and frequent communication.
ii. At Redwater:
   a. Unitization discussions were terminated when it was discovered that there was an active bottom water (A third party came in to build the water handling facilities).
   b. Lease holders were not interested in forced unitization.
iii. Pembina Cardium has fragmented ownership.
iv. Swan Hills was unitized during waterflood operations. However, new technologies have redefined the meaning of a reservoir/pool, extending all the way to the source rocks which have now become attractive economic targets. Therefore, halo areas may present a problem by extending past the water flood areas which were previously unitized.
v. Judy Creek was unitized. It was critical to the success of secondary and tertiary recovery, but how do you ring-fence the area?

E. Discussion:

i. It is best for owners to get together and unitize. Good communication is the key to cooperation.
ii. Perhaps, first a meeting between Government and owners to brainstorm what incentives Government can use to encourage "functional units" in CO_2 EOR schemes is needed. This first meeting could be set up and facilitated by Government.
iii. ERCB (or another Government agency) should be a neutral arbitrator to decide unit ownership (e.g. 6 different methods to determine porosity – company uses method which is advantageous to them). The crown could control the unitization through pore space rights in Bill 24.
   a. ERCB will not accept that role because of potential liability due to company law suits.
   b. Companies have to agree to have ERCB as the arbitrator and agree not to sue, or
   c. ERCB could appoint an independent arbitrator,
   d. ERCB should focus on conservation and let it be the guiding principle.

BARRIER 7: MISCELLANEOUS

A. Infrastructure:

i. Many oil fields where CO_2-EOR is applicable are depleted from primary recovery and have extensive infrastructure (wells and pipelines) already in place. The initial capital cost could be decreased by reusing and refurbishing as much of the old infrastructure as possible. The longer the time between primary recovery (or secondary) and CO_2-EOR the less likely it will be that the existing infrastructure can be reused. Legacy oil pools have declining infrastructure and it may already be too late to use that infrastructure for EOR without expensive retrofit. Facilities and infrastructure for CO_2 injection need to be CO_2 friendly. Can the cost to retrofit or replace be justified based on the incremental oil to be recovered.

ii. Pipelines:

  a. Older technology has resulted in decay in the pipeline infrastructure (could put liner in). Pipeline issues are mostly external corrosion (Black wrap pipe was not designed for higher temperature operations used more frequently today.).

  b. We are also, once again, in a pipeline constrained situation with regards to available capacity, so it may be more beneficial to build new pipelines for CO_2 transport.

iii. Wells: Existing wells in the legacy reservoirs can be more easily and economically made CO_2 friendly by retrofitting with new tubing.

B. Government and Policy:

i. In Alberta it is hard to find out who to talk to and they are bound to be precedent and rules that are in place. BC and Saskatchewan are easier to talk to. Regulatory red tape and time on Alberta side is way too slow compared to Saskatchewan. Saskatchewan governmentt (MER) is keen to see technology advanced. Alberta historically gave away too much in the past in the EOR royalty rules (section 4.1 of the Alberta regulations).

ii. Alberta may need different strategies and regulation when dealing with large global oil companies, as they may want to shut Canadian oil in and produce from other countries (e.g.Venezuela).

iii. Incentives are needed that will force conservation and not high grading.

iv. Regulations associated with an EOR project versus CCS project are different, especially with respect to monitoring.

v. Government forces companies to abandon pools and then cannot reuse wells.

vi. For ERCB Directive 51 with respect to acid gas well regulation, it is difficult to understand the rationale for changes proposed: cementing, completions and logging requirements are cost prohibitive. Joffre Viking wells would not qualify. Need better industry communication.

vii. Industry does not want a moratorium on tight oil while waiting for strategies and policies to be decided.

C. Royalty and Credits:

i. New technology funding (royalty credits) gives up confidentiality after 5 years.

ii. Taxing CO_2 emissions is not the answer. Small companies get caught in regulatory cross-fire (regulatory micro-management requires recording and documenting each barrel of oil produced).

iii. Grand-fathered facilities are not subject to CO_2 emission penalty (difficult to incent EOR under current legislative environment).

D. Economics:

i. The dynamics have changed. Planning for trying to get rid of CO_2 from oil sands upgraders that will never be built is not necessary.
ii. We are somewhere between a free and controlled market. If development is too fast, slow it down.
iii. Upgrading separate from refining is inefficient.
iv. Alberta will lose the competition with the U.S. because it is cheaper to do EOR there.
v. Small companies can't do EOR because they can't make long term commitments.
vi. Small companies would be happy with low rate production from EOR, but can't afford large capital expense.
vii. Operators typically give their research teams the worst wells to work with so they do not perform even to average expectations in pilots.
viii. EOR is very labor intensive:
    a. from planning, permitting, operations, blowdown, G&A costs (e.g weekly simulations, PhD consultations , lab, testing, etc.)
    b. It can take weeks to run simulations on large reservoirs, with multiple runs required to tune a model

E. New Initiatives:

i. PCOR looking at putting CO_2 into Bakken – paper and lab study
ii. Lashburn Husky project has once-through steam generator (OTSG) within a few km of CO_2 pilot Three processes for CO_2 capture:
    a. Hindered amines HTPE
    b. Inventys Veloxsotherm bed solid adsorbent (from Ballard fuels)
    c. CO_2 Solutions (Quebec) – developed enzyme that enhances the uptake of CO_2 similar to human body (enhances MDEA reaction rate)
    d. At $75/tonne CO_2, can still make profit
iii. Insitu combustion to generate a mixture of steam and CO_2 at surface. Nitrogen and CO_2 separate downhole due to preferential solubility of CO_2 into the oil.

F. Technology:

i. If VRR < 1, then oil re-saturates reservoir rock.
ii. The longer CO_2 stays in the ground , the more oil recovered, so design process to keep CO_2 in the ground as long as possible.
iii. Maybe CO_2 is the wrong solvent when methane can be used and is a comparable cost and has better resale value on recovery.
iv. Methane may also be considered safer than CO_2.
v. CO_2 versus hydrocarbon flood – CO_2 is not 1st contact miscible compared to hydrocarbons and is therefore a more complicated process.
vi. CO_2 will dissolve readily in water and you can lose it there, and CO_2 may preferentially sweep water before sweeping oil.
vii. Other than cheap methane, HC solvents can be a costly way to mobilize oil (~7mcf/bbl is needed)
viii. A few % difference in solvent recovery can break the economics.
ix. When CO_2 breaks through, the water/oil cut increases.

G. Barriers to Pioneer (Pembina Cardium) not going forward:

i. Competition for money with unconventional oil exists.
ii. EOR producer would have been required to commit to a multi-year CO_2 contract, in the order of 10-20 years.
iii. The CO_2-EOR technology was not demonstrated in Pembina (e.g. Well spacing due to tight permeability-- required infill drilling).
iv. Directional permeability could cause containment issue but horizontal well siting could potentially alleviate this.
v. High perm zone target zone could be a thief zone (more comfortable in the sands with more homogeneous [predictable] permeabilities).
vi. If you got Government to guarantee to buy CO_2 supply over the long term and resell it, then more projects would likely go ahead (like gas gathering system – not take or pay contracts).

H. Discussion:

i. Policy and Regulation
   a. Government needs to develop longer term investment strategies and look at complete value chain from primary through EOR to abandonment and reclamation.
   b. Government, industry or both, need to put together a super team to design a pilot the way it should be done.
   c. Government is marching down mega-project path, but we need more small projects, so more government incentives at that level are needed.
   d. ERCB needs to balance their regulations more:
      - strict on conservation and unitization and
      - less strict on wells.
   e. The current Licence Liability Rating (LLR, ERCB Directive 006) program allows companies not to abandon wells, but to sit on wells and tie up reservoir development.
   f. There could be a huge upside for new policy and regulations to book more reserves. Government should incent, but not regulate development. How do you incent?
      i. Incent research and development and piloting
      ii. Oil and gas companies would like to see 50:50 funding split with government. Operators don’t mind playing the guinea pig as long as government comes to the table.
   g. There does not appear to be any government funding available from AI-EES to assist EOR. Innovative and sustainable technology needs to be stimulated by government from a deployment standpoint.
   h. Need a “bridge program” to keep facilities at legacy oil pools useable until the resource can be fully captured.
   i. Don’t incent oil sands and horizontal wells and multistage fracing without incenting EOR.
ii. Royalties and Credits
   a. The question of granting CO_2 credits for EOR still needs to be addressed. The company doing the storage (purchase) of CO_2 should receive the credits over the company doing the capture, since the purchaser of the CO_2 can now use credits to purchase the CO_2.
iii. Economics
   a. Rural oil pools close to small communities are declining, closing down and workers migrate. Government should provide incentives to keep the rural communities viable. CO_2-EOR could revitalize employment.

b. Part of the value chain with respect to regional socio-economic impacts: When pools in a development area are depleted, then regional economics suffer and communities die. Government needs to factor in the effect of regional economic benefits of maintaining production in a region with established social infrastructure, by incenting EOR in those regions. (In Ontario, industrial tax rates are coupled to residential tax rates). EOR projects would address these social issues.
   - Need to consider municipal socio-economic impacts as part of the value chain around integrated projects.
   - Closing a field, puts O&G development in an area over a fiscal cliff and the local communities could follow suit.
   - On the other hand, communities should not tax oil development out of existence. Tax should be in line with services
c. Smooth out cycles: In boom times, tax companies for research funds; pay back in bad times for company research to keep people employed.
d. Need to design EOR projects so that economics of front-end capital balances to long-term production decline to provide optimal net present value (NPV). CO_2 flood can have fewer wells at larger spacing than waterflood due to viscosity and mobility of CO_2.

OPPORTUNITIES

The ERCB has one of the best databases in the world for oil and gas. The value of that database lies in the currentness and completeness of geological and reservoir data and the public availability of that data. During the drilling, development and operation of EOR and unconventional plays, there is an opportunity to gather and publicly disseminate data that would be valuable to optimize future EOR and unconventional operations. Companies have made successful businesses out of using the ERCB databases to provide reservoir information in a format that is easily accessible to users. The work done by Sproule (2013) for the ERCB and Epic (2006) for PTAC to extract from the ERCB database information for Enhanced Recovery should be built upon so that it can form a useful tool for oil and gas companies to develop strategies around CO_2 – EOR. This data can be further enhanced by using the high level scoring approach as described later in this report; or after the improvement made to this model as suggested by AITF described in Appendix 2; or by using the model, Select EOR (formally PRIZE) provided by AITF for EOR assessment. Development strategies for some of the main CO_2 – EOR candidate reservoirs has evolved through a modeling study led by ARC (2009). Not all CO_2 – EOR prototype oil pools found in Alberta were examined. This study could be extended to other prototype pools or the prototypes models already developed could be compared to CO_2 – EOR pilot data or the models could be used to develop new field pilots. This could be developed in a comprehensive manner by developing a risk management framework which utilizes these options to identify the risks and quantitatively access them. This approach is discussed in more detail later.

Five to 10 years ago, there was strong interest in developing CO_2 – EOR as a follow-up strategy to secondary and tertiary recovery. The Alberta government encouraged this by their RCP and IETP programs which resulted in 7 CO_2 – EOR Pilots being established. Of these pilots, six (Swan Hills, South Swan Hills, Judy Creek, Redwater, Zama and Pembina Cardium) were technically successful and compared favorably to commercial CO_2 – EOR commercial operations in Canada at Joffre Viking and Weyburn. The data from these 7 pilots is publically available from the ADOE and can be used for a more quantitative technical assessment as illustrated later using cumulative production and injection data. These ADOE reports contain annual, quarterly and daily injection and production data as well as compositional data. An in depth analysis of the 6 pilots that passed the high level technical assessment should be done by an independent consultant.

This could help identify pools where CO_2 will be easily miscible, having regard for such things as bottom water, secondary water flooding and other pressure (miscibility) factors. In addition, more detailed studies are required to assess sweep efficiency.

Commercial development did not follow from these pilots because of the lack of a continuous CO_2 supply at an affordable price ($1 to $3/mcf). In fact, there appears to be a disconnect between the potential large CO_2 suppliers such as the utilities and the oil companies who would produce the oil, over acceptance of risk and the price of CO_2. To address this issue, it is suggested that the government work with the two groups to further develop a netback economic calculation (similar to the one presented later in this report) for the potential CO_2 – EOR reservoirs in Alberta to get agreement on an affordable price of CO_2 so that the potential CO_2 suppliers can respond.

Currently, commercial interest in CO_2 –EOR has decreased further due to the arrival of new oil opportunities. Tight oil and gas have become economically attractive due to primary production from multistaged fraced horizontal well technology in oil source rocks and in haloes around some of the large oil pools (e.g. Swan Hills and Pembina Cardium). Even though there are steep decline curves and only 3 to 6% of the OOIP is recovered, the rapid financial return makes it more attractive and less risky than CO_2 – EOR which is capital intensive, similar to oil sands. Now is the time to develop a long-term investment and development strategy for CO_2 – EOR to optimize resource recovery and utilization of existing infrastructure (discussed more in the following paragraphs). This strategy needs to look at full life cycle of the resource to optimize oil recovery while at the same time maximizing CO_2 sequestration. The appropriate mix of guidelines and incentives are required similar to what has been done with oilsands and unconventional oil and gas.

The orientation of horizontal wells for primary production in the tight oil plays may compromise secondary and tertiary recovery. Studies should be completed looking at the whole oil recovery cycle to optimize the maximum recovery of the OOIP. This is particularly important in the cases such as tight oil where the recovery factor for primary is so small. In order not to "sterilize" the resource, research feeding into field pilots in areas where the primary recovery phase has been completed would pay off in the "long run". It is quite possible that CO_2 –EOR will have a role to play. Two research organizations (PCOR and AITF) are evaluating this potential in the laboratory, but field pilots should also be funded to better understand how to undertake primary development of tight oil in order to promote secondary and tertiary recovery methods.

Huff and puff has been discouraged because of the slower oil recovery rate. However, there are niche applications, similar to steam floods in the oil sands, to get interwell communication while still recovering oil. Husky is pioneering this technology for heavy oil (API of 12^o) in the shallow CHOPs area around Lloydminster. Wormholes created during primary production allow good returns when immiscible CO_2 Huff and puff is used for secondary recovery of heavy oil. This goes against convention wisdom which argues not to use CO_2 floods below an API of 22^o and that the pool pressure needs to be elevated above the MMP. Huff and puff should be looked at as a secondary recovery method in tight oil as well as heavy oil. Commercial scale operations may provide additional advantages for huff and puff, where, similar to cyclic steaming in oil sands, oil production may be made continuous by switching between wells on production and wells on injection at the end of each half cycle. Also, well completion strategies for primary and follow-up recovery methods, need to be part of the overall long term development strategy.

Another source of new oil which cannot be produced on primary or by waterfloods is found in the ROZs. CO_2 floods are the most attractive method to recover this oil. These ROZs may be attached to large reservoirs currently being produced or may be detached related to historical oil transport pathways through regional aquifers (e.g. the Golden Trend). This is a resource that is currently "undiscovered". Use of the ERCB historical data on well logs would allow mapping of the potential oil resource that exists from the occurrence of detached ROZs in Alberta. This could be done by the Alberta Geologic Survey, by AITF or a consulting company such as Sproule. Additional core and log data may need to be gathered to define ROZ potential areas. It is important to gather the core and log data while wells are being drilled through zones that previously were considered non-productive. The ERCB and AGS can play a significant role here. A further consideration is the depressuring of ROZ areas attached to producing oil or gas plays. In much the same situation as gas-over-bitumen or associated oil pools, depressurization of associated gas can reduce ultimate recovery of oil. The longer term pressure and depletion strategy needs to be addressed at the beginning of development. CCS may play a big part in providing pressure maintenance for ROZ plays and should be part of the overall strategy.

Many oil fields where CO_2-EOR is applicable are depleted from primary recovery and waterflooding and have extensive infrastructure (wells and pipelines) already in place. The initial capital cost for CO_2-EOR could be decreased by reusing and refurbishing as much of the old infrastructure as possible. The longer the time between primary recovery (or secondary) and CO_2-EOR, the less likely it will be that the existing infrastructure can be reused. Also, as the primary pools close down and workers migrate, the communities who depend on the taxes from the oil companies can also wither and die. Government should provide incentives to keep the rural communities viable. CO_2-EOR could revitalize employment. A "bridge program" is needed to keep facilities at legacy oil pools useable until the resource can be fully captured. This means that a CO_2 supply needs to be available. If you got Government to guarantee to buy CO_2 supply over the long term and resell it, then more projects would likely go ahead. Market driven "take or pay" contracts do not work well because the CO_2 demand for CO_2-EOR is too variable. A more flexible system, like a gas gathering operation, that can guarantee uptake of natural gas when available, but does not require a constant supply would be desired. Also, integration of CCS with EOR may be the "tipping block" that makes the project go. Both CCS and CO_2 – EOR are capital intensive. They can be integrated to utilize common infrastructure for CO_2 storage, production and recycling. For example, CCS can also be used as a means to store excess CO_2 while the EOR scheme is ramping up or ramping down. This helps to allow for a steady CO_2 supply while accounting for a fluctuating CO_2 demand by the EOR operations. If CO_2 credits could be banked as soon as the CO_2 enters the oil reservoir and withdrawn as the CO_2 breaks through and is produced, this would further incent CO_2 – EOR projects. Particularly attractive are vertical gravity stable CO_2 floods in large reefs such as Redwater where more CO_2 is used to flood the HCPV than horizontal floods and maximizes storage as there is little CO_2 breakthrough to the producing wells. The company doing the storage (purchase) of CO_2 should receive the credits (not the company doing the capture), since the purchaser of the CO_2 can now use credits to purchase the CO_2. Development of policy based on maximization of the oil resource recovery can play a large role in the attractiveness of CO_2 – EOR projects.

Although, CO_2 supply and unitization were not the main emphasis of this study, they can be the showstopper as described earlier under Barriers 4 and 6. The right balance of royalty and tax incentives need to be in place, having regard for what is being done in other resource plays like oilsands and unconventional oil and gas that compete for investment dollars. Also, full life cycle for EOR as well as CO_2 sequestration need to be considered. With regard to CO_2 supply, there is currently a limited supply in Alberta of relatively inexpensive and pure CO_2 from industrial sources (oilsands upgraders, fertilizer plants, etc). This supply should be considered for EOR potential before CCS. As previously discussed, an opportunity exists for a development that would have the CCS scheme integrated with the CO_2-EOR scheme, having consideration for shared infrastructure and operational flexibility. Governments may play a key role in facilitation or through participation.

Communication needs to be established at a number of levels to help address these 6 barriers. This has been done in the past in similar situations by government review panels. In addition, the Alberta government could organize conferences around areas of interest to the province and specifically invite the oil and gas companies to present at them. That is, the government should organize the conferences, and not do it through oil company volunteers. One topic could be follow up strategies to primary production of tight oil or resource evaluation of ROZs. Or the two could be combined with others (such as a review of Alberta's CO_2 – EOR pilots) in a conference on strategies to utilize CO_2 to increase oil reserves in Alberta. The organizer would have to be guided by technically competent consultants. This could be done through PTAC, but the government should control the direction and content of the conference. The oil and gas companies naturally don't want to share information – they need a push which could be one goal of these conferences. Internal conferences in oil and gas companies following such a government organized conference should also be promoted where the conference straddles traditional structure (e.g. conference organized between the exploration and production departments) to further generate interest by individual companies. A mechanism for feedback from these internal oil and gas company conferences to the government should be provided. Perhaps, the feedback could be sought from these oil and gas company internal conferences to generate more government organized conferences with the goal to find a mutual beneficial solution to increase the oil reserves of the province.

Overcoming the Barriers to Commercial CO_2 – EOR in Alberta, Canada
Part III: Development of Assessment Tools and Proposed Path Forward

A number of opportunities have been presented to address the barriers to having more commercial CO_2 – EOR operations in Alberta. Now a plan is needed to utilize these opportunities in a cohesive fashion. As a start, three tools are developed to assist in decision making. They will be treated independently under the headings “Technology”, “Economics” and “Policy”. Even though each tool would prove useful at this early stage of development, they need to be integrated into a risk management plan in the future to maximize their value as discussed at the end of this section.

I. TECHNOLOGY

In the opportunities section, the Alberta ERCB data base was identified as a resource that should be developed further for assessing EOR opportunities. A number of studies that have built on the database were identified. Each study used specific parts of the ERCB database. However, we found that none of them offered a simple way to combine the CO_2 – EOR pilot data with pool data to compare one site to another. We developed the following deterministic methodology to score the Alberta oil pools which had CO_2 – EOR pilots done on them. The results although reasonable are not unique. However, the methodology allows for scenario analysis and is easily adaptable into a risk assessment framework for a more comprehensive analysis. An alternate approach which may be preferable but has not yet been developed is described in Appendix 2.

Ranking of Western Canadian Sedimentary Basin (WCSB) reservoirs for CO_2-EOR

One of the goals of this study was to identify consistent methodologies or improve on existing methodologies as a basis to evaluate CO_2 – EOR projects. Screening and ranking methodologies fall under this banner. A number of similar schemes have been described for screening CO_2-EOR projects at a high level (Taber et al., 1997) and most recently by Sproule, 2012) with sparse data. They are based on hard thresholds or qualifying criteria. A more useful scheme is one that has two steps; a screening followed by ranking through scoring such as done for Alberta by Edwards (2000), Shaw and Bachu (2002), and Bachu and Shaw (2004). Once the site has passed the qualifying or screening criteria, each qualifying criterion is transferred to a dimensionless curve (also referred to as a utility curve) ranging between 0 and 1 with zero being the worst value and one the best value for that particular criterion. In addition, non-qualifying criteria are added which only have soft thresholds and dimensionless curves are constructed for them also. The distinction between hard and soft thresholds is that a hard threshold defines the value where the project is no longer acceptable and is eliminated from consideration, whereas soft thresholds are the value of the property when the dimensionless curve reached it maximum or minimum (i.e. 0 or 1) and remains constant thereafter. Together, these qualifying and non-qualifying criteria form the preferential criteria. Each of the preferential criteria is assigned a weight; the sum of all the weights being 100. The weights represent the relative importance of each criterion. These are set here using CCS and EOR expert opinion. They can be adjusted by the decision-maker of the study but must be consistent between project comparisons.

For each potential EOR site, the attributes are assigned a value between zero and one using the dimensionless curves which in turn is multiplied by the weights to yield a criterion score. The criterion scores are summed to give a score for that site, the maximum score being 100. This methodology can be used to rate one site against another. These scores are situational and decision-maker specific and thus are relative scores; two decision-makers may assess the projects and criteria differently. All criteria must be the same for projects to be compared. If values are not available for a criterion of one project, then it cannot be ranked against the other projects. If a criterion does not apply to a project then it would receive a zero on that criterion. If a standard method is used with consistent dimensionless curves, then all projects can be compared on an equal basis. Decision-makers can, however, make individualized assessments with this model if they do not agree with the standard dimensionless curves.

In the past, the screening criteria used were depth, temperature, initial pressure, porosity, permeability, oil gravity, oil composition, oil viscosity, net thickness, oil saturation, original oil in place (OOIP) or remaining oil in place (ROIP) and recovery factor. Some of these properties are dependent on each other. Depth is related to pressure (i.e. pressure increases with depth) as is oil gravity to viscosity (viscosity decreases with increasing oil API gravity and temperature). Any scheme must consider these interdependencies. Other properties, in addition to these properties which should be considered are heterogeneity (both geological and structural), gas cap, aquifer support, suitability for CO_2 storage, competing technologies, cost of CO_2 source and existing infrastructure.

Interdependencies

There are two factors that determine the success of a CO_2 flood. One is the displacement efficiency which operates at the pore scale and is a result of the interfaces formed between oil and water, water and CO_2 and oil and CO_2, and the relative mobilities of the three phases, oil, water and CO_2. The dissolution of CO_2 into the oil alters its properties substantially, changing its density (the oil swells), its viscosity (the oil flows more easily) which leads to a higher mobility of the oil relative to water, and its capillary properties (which lowers the residual oil saturation). A challenge is to dissolve the CO_2 into the oil because of the much higher mobility of the injected CO_2 relative to the oil, which results in the CO_2 bypassing the oil before it can completely dissolve in it; and the decrease in the diffusion rate of CO_2 dissolving in the oil as the oil becomes heavier. To reduce this tendency, most CO_2 floods utilize a tapered Water Alternating Gas (WAG) strategy with the water slugs increasing in size relative to the CO_2 slugs over time.

Maximum recovery using a CO_2 flood is usually reached by achieving miscibility between the CO_2 and the oil. This depends on pressure, temperature, oil gravity and viscosity. Several relationships have been proposed. One such relation is:

$$MMP = 15.988*T(0.744206 + 0.0011038*4247.98641*API^{-0.87022}) \text{ ……..(1)}$$

Where MMP is minimum miscibility pressure in psi. T is reservoir temperature in ^oF (after Cronquist, 1978) where an API function from IEA, 2009 has been used to represent the molecular weight of the heavier fraction of the oil (MW C5+).

The relationship between oil viscosity, API gravity and miscibility is shown in Figure 1 for immiscible and miscible projects. API gravity is dependent on oil composition with the heavier molecules decreasing the API gravity. As expected, the immiscible projects are at the lower API gravities (<30) and higher viscosities (> 1 cp) although there is some overlap. Also the miscible projects have oil viscosities falling on either side of the water viscosities before dissolution of CO_2 into the oil; and the API gravities range from 25 to 50. As the CO_2 dissolves into the oil, the viscosity will decrease and the API gravity will increase. Above 10 MPa, pure CO_2 viscosities range from 0.03 to 0.1 cp for temperatures between 20 and 100^0C which suggests around an order of magnitude viscosity difference between the pure oil and the CO_2.

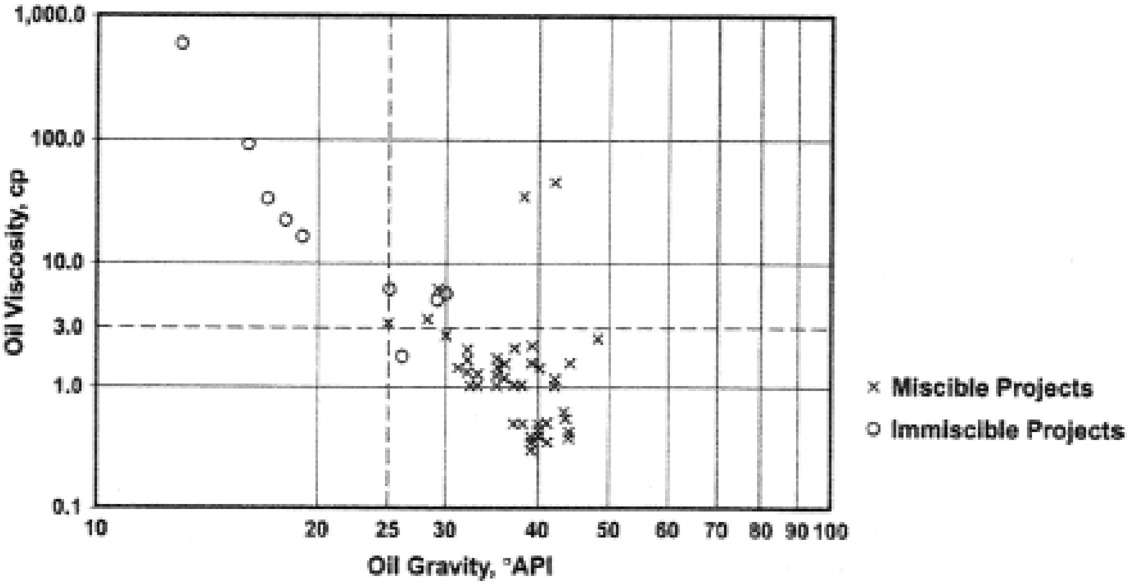

Figure 18: Oil viscosity versus API gravity (figure 3.1 from Jarrell et al., 2002)

Sproule (2012) provided a correlation between oil density (kg/m^3) and viscosity for oil (cp) at 15^{0}C (Figure 19):

Log (viscosity$_{15C}$) = 1.5654E-09$(d_{oil})^4$ - 5.1019E-06$(d_{oil})^3$+ 6.2539E-03 - $(d_{oil})^2$ 3.4053E+00(d_{oil}) + 6.9306E+02 …(2)

This was based on 3,215 oil samples from Alberta, ranging from 681.5 to 1,012 kg/m^3 or 8.3 to 76.1^0 API gravity. Dead oil viscosity at temperature was estimated by applying the ASTM correlation with slope B, estimated by:

B = 4.46E-03(d_{oil}) - 7.88E+00 ……………………………………(3)

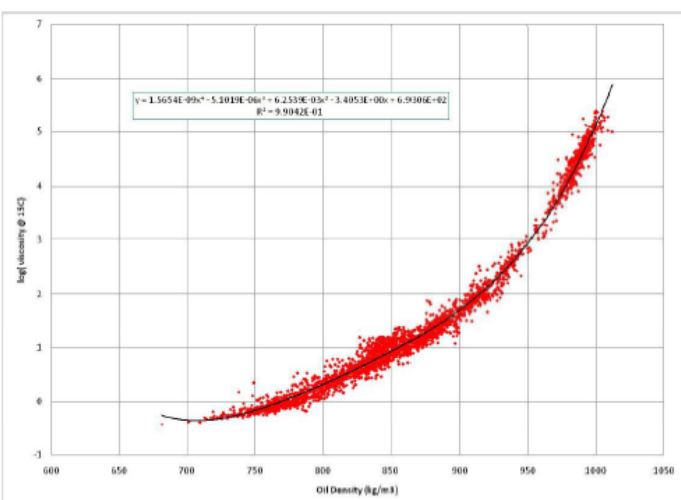

Figure 19: Oil viscosity (cp) at 15^{o}C vs oil density (kg/m^3) for Alberta oil samples (Sproule, 2012)

The other factor that determines the success of the CO_2 flood is the volumetric sweep which is affected by gravity and the geological heterogeneity of the reservoir. The CO_2 will tend to sweep the top of the reservoir due to gravity. The densities of CO_2 above 10 MPa range from 0.2 to 0.9 for temperatures between 40 and 100^{o}C compared to the oil and water which tend to lie in the neighbourhood of 0.7 to 0.9. The density differences between all three decrease at higher pressures. Heterogeneity can improve or have an adverse effect on the volumetric sweep. The Dykstra Parsons coefficient (DP) of permeability variation is a common descriptor of reservoir heterogeneity. It measures reservoir uniformity by the dispersion or scatter of permeability values (Jarrell et al., 2002)). A homogeneous reservoir has a permeability variation that approaches zero, while an extremely heterogeneous reservoir would have a permeability variation approaching one. Lower values of DP favor better volumetric reservoir sweep efficiency. Other factors also affect the reservoir heterogeneity which are not easily quantified (e.g. layering, compartmentalization, fracturing).

Alberta pilot ranking and scoring

Using this approach which is currently the "state of the art", the property data from Tables 1a, 1b and 1c were used to rank the Alberta reservoirs. The information available from the pilots allows for the introduction of some additional scoring parameters based on injection and production data.

CO_2-EOR pilots are designed to test the opportunity for developing secondary or tertiary recovery in their respective pools. The results from the pilots are used to extrapolated to their oil pools to evaluate the attractiveness of potential commercial operations. Consequently, if pilot data is available, a mix of this data plus the larger pool data should be used to make the evaluation. A series of criteria have been developed to evaluate such oil pools if no pilot data is available. These were split into fluid properties, reservoir or pool properties, and economics. Fluid related properties are depth (as it is related to pressure), temperature, API gravity or density, viscosity, initial pool pressure/MMP, and S_{oil} (oil saturation; original and remaining). Some of these properties are dependent on each other so that only one need be used (i.e. depth is replaced by temperature and pressure, API gravity is related to viscosity). Reservoir related properties are oil in place (either Original (OOIP) or Remaining (ROIP), recovery factors, thickness, porosity, permeability, strength of aquifer support, presence of a gas cap, geological heterogeneity and structural heterogeneity. Economic properties are approximated by existing infrastructure, competing technologies, storage capacity and cost of CO_2. Those economic properties which are common to all reservoirs such as price of oil are not considered at this stage. The economic properties mentioned here are simplistic but are treated in more detail and more rigorously in the next section. The economic properties are not used when pilot data is available for a technical comparison of pools. Also a number of fluid and reservoir properties mentioned above are not considered. Effectively the pilot data such as well spacing, number of wells, CO_2 injected, CO_2 produced, CO_2 injection time, water injected, water produced, gas produced, and pressures replace the fluid properties including depth, temperature and pressure; and the reservoir properties such as heterogeneity. The fluid criteria retained were P/MMP, API, viscosity and S_{oil}. Although API and viscosity are correlatable, there is enough of a discrepancy to use both of them with the emphasis on API. For the reservoir criteria, ROIP (OOIP – cumulative production) was used instead of reserve estimates as the latter depends on technology available at the time the reserve estimates were made. With the advent of horizontal wells and mulitistaged fracing, reserve estimates will increase over those currently used. In order not to eliminate EOR candidates because of low reserve estimates, ROIP was used as relative measure of the oil available for tertiary production. Thickness and porosity were maintained as criteria whereas permeability was not, as the permeability, in these pools is quite variable and an average permeability is meaningless. Rather the injectivity of CO_2 in vertical wells in the pilot was used as a measure of the permeability and thickness. Neither aquifer support or the presence of a gas cap were used as criteria as it was felt that their influence is reflected in the production characteristics such as processing rate, WOR and CO_2 Utilization factors. The pilot properties were all scaled to ratios, percentages or per well so that the pilots could be directly compared to other pilots or commercial operations and did not depend on area or number of wells. The rationale for this is shown below.

Figure 20 shows a commercial CO_2 miscible flood with respect to production rates and oil/water cut over time.

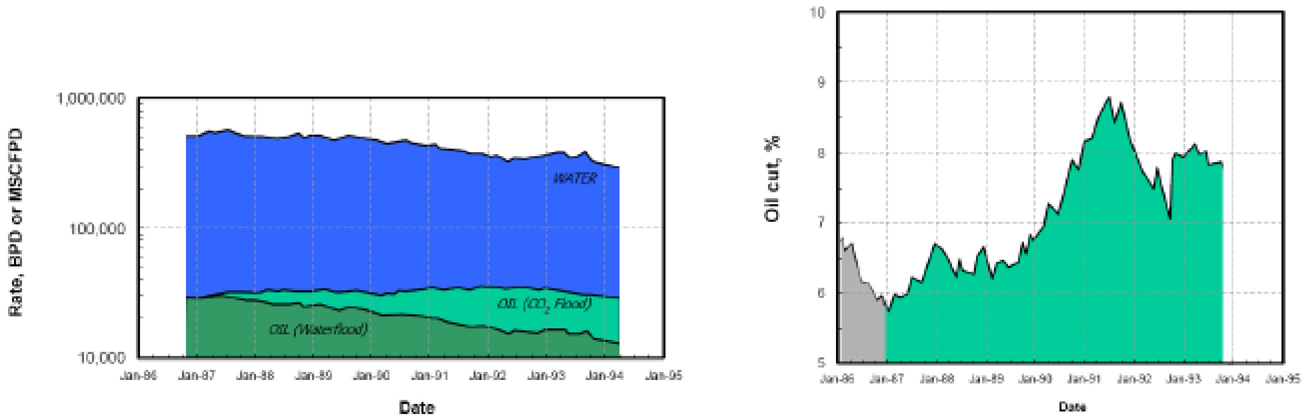

Figure 20: Rangely Weber Sand Unit CO-EOR Flood (a) production and (b) oil cut. CO_2 flood started in Jan 1987 (after Lake & Walsh, 2008)

Lake and Walsh (2008) used commercial floods such as these to develop a simple model (Figure 21) based on hyperbolic decline curves and material balance for predicting CO_2-EOR based on waterflood behavior. They derived the necessary relationships from commercial CO_2-EOR floods in the continental U.S.. At point t_1, the CO_2 flood commenced. The difference, $t_2 - t_1$ is the lag time before the effect of the CO_2 injection on enhanced oil recovery occurs. The oil production rate peaks at time t_3 and t_4 is the end of the EOR process. Assumptions are (1) the waterflood decline curve is hyperbolic, (2) EOR oil production rate curve between t_2 and t_3 is linear, and (3) the CO_2 –EOR decline curve is also hyperbolic. These fit of these three curves (dashed lines) relative to the actual production rate data (solid line) is shown in Figure 21. Walsh and Lake (2008) state: “Although an oversimplication, the model is more than adequate for screening and economic evaluations.”

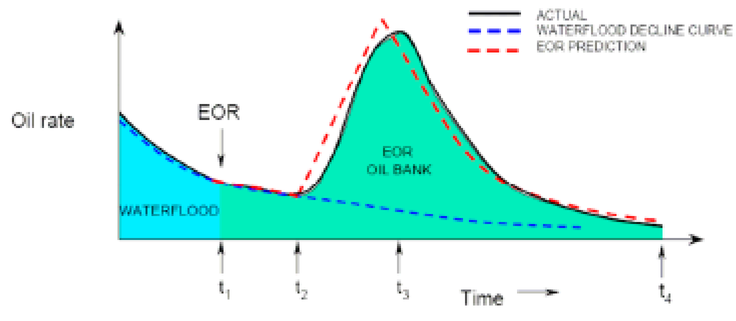

Figure 21: Model for CO_2 miscible flood (after Lake and Walsh, 2008)

Standard data from the Alberta CO_2 EOR pilots are injection rates, production rates and pressures. Pressures were not used for the analysis because all seven of the pilots were required to run the CO_2 flood above or close to MMP. Six criteria from the pilot data were considered to score the oil pools for CO_2-EOR attractiveness:

1. All the Alberta CO_2-EOR pilots were completed before peak oil production rate was reached (i.e before t_3 is reached in Figure 21). Using the approach of Lake and Walsh (2008), it was assumed that the ramp up in oil production rate from CO_2 injection would be linear, and therefore the cumulative oil production would be a concave curve when plotted against time or HCPV with the slope steadily increasing. The steeper the slope, the more rapid the processing rate during the ramp up period. After peak oil at t_3, the oil rate decays and the rate of cumulative oil production versus HCPV would decrease resulting in a convex curve. Taken together the cumulative oil – HCPV curve would be "S" shaped over time as the cumulative oil production increases. Ideally, the average rate of oil production should be compared at the same HCPV for all the pilots. This was not possible. Instead, to calculate the average rate of oil production, the cumulative oil (bbl) plus HC solvent production (boe) were divided by the time interval from the start of CO_2 injection to the end of CO_2 injection (or at some earlier time during CO_2 injection if the CO_2 injection was still continuing past the time of data coverage) as measure of the oil processing rate (bbl/day). This processing rate was normalized to a single production well by dividing by the number of production wells. In some cases the cumulative oil production continued past the cessation of CO_2 injection. The average processing rate would be sensitive to this as well as the position of the pilot on the ramp up curve and the lag time between the start of CO_2 injection and initial response.
2. The maximum CO_2 injection rate/well (mcf/day) was used as a permeability-thickness indicator. The higher the injection rate, the higher the permeability-thickness product.
3. Both the CO_2 gross utilization factor and net utilization factor (tonnes CO_2/bbl oil) were calculated. Lower utilization factors are better.
4. The injected CO_2 normalized to the total fluid injected (i.e. oil + water injected) was used as a measure of the efficiency of both CO_2 storage and oil production, since pore space occupied by water is not available to be occupied by CO_2 and water injected is not accounted for in the HCPV flooded.
5. Finally the average water/oil ratio (WOR) was used as excessive water handling can make an EOR project unattractive.
6. The produced gas to oil ratio (GOR) was not used as it is accounted for in the solvent gas produced, recycled CO_2 and oil produced.

Dimensionless utility curves and weightings
The thirteen scoring dimensionless (utility) curves for the ranking properties appear in Appendix 1 where they are discussed in detail. Specifically, curves are drawn for API gravity, P_i/MMP, viscosity, $S_{oil(i)}$, ROIP, average pool thickness, average pool porosity, injectivity (i.e. Permeability-Thickness factor), % CO_2 injected versus water injected (Storage Efficiency), CO_2 injected to produced oil (CO_2 Gross Utilization and CO_2 Net Utilization), daily oil production (Incremental Oil Processing Rate) and the amount of water relative to the oil produced (WOR). The thresholds of the utility curves ranging from zero to one and their critical property limits are recorded in Table 2.

For each of these thirteen criteria, weights were assigned as an indication of their relative importance to the potential success of a CO_2-EOR project. In Table 2, the weightings can be compared. It can be seen that 4 properties dominate the weights: ROIP, CO_2 gross utilization, oil processing rate and WOR. On the smaller scale, the oil processing rate, coupled with the gross utilization factor and the WOR are the three pilot properties that are related specifically to the oil produced, and are of high importance. On the larger scale, in the Fluid and Reservoir Properties, one criterion stands out. The ROIP which is the amount of oil currently stranded in the oil pool is a measure of the total oil which would be the commercial target for a CO_2-EOR operation. Although the current oil saturation might be a preferable criterion compared to the initial oil saturation, it is not easily extracted from existing data. Consequently the initial oil saturation was used as a proxy for the latter and due to the uncertainty introduced, it was weighted less strongly. As viscosity is related to the API gravity, it was rated lower than the API gravity to eliminate any redundancy. The pressure ratio (P_i/MMP) was weighted low because all the pilots were run close to the MMP and it was felt that this criterion would not play an important role in the scoring of these 8 pilots. Pool thickness and porosity are important but these properties are also reflected in some of the pilot properties. Again to avoid redundancy, they were also given lower weights. The injectivity in the reservoir is important . Here, it was measured by the maximum rate of CO_2 injection which depended not only on the pressure build up but also on the availability of the CO_2 as supply was limited for these pilots. Due to this uncertainty, a lower emphasis was placed on it in the scoring. Storage efficiency was also not highly rated as the projects were being rated for their attractiveness for CO_2 – EOR, not storage. Storage would be important from the standpoint that it could make the EOR project more attractive, as potentially it could become a second revenue stream during or at the end of the EOR project. However due to the large uncertainties of commercial CCS projects going ahead and whether EOR would qualify, this property was rated lower. The CO_2 net utilization was also rated poorly because the data being considered is only for pilot projects which have generally injected less CO_2 than 20% of the HCPV. Note that the weightings can be adjusted as circumstances change over time (e.g. more CO_2 injected) and depending on the purpose of the evaluation (e.g. oil production versus storage).

Table 2: Utilities and Weights for CO_2-EOR project assessment with pilot data

CO_2-EOR Qualifying Properties for Screening and Preferential Properties for Scoring						
Property Class	***Property***	***Thresholds***				***Weight***
		Units	***Limiting***	***Utility = 0***	***Utility = 1***	
Fluid Properties	API	º	>22	22	45	5
	P_i/MMP	Ratio	>0.6	0.8	1.5	2
	Viscosity	cp	<50	50	0.1	2
	S_{oil} (initial)	fraction	>0.2	0.2	0.90	5
Reservoir (Pool) Properties	ROIP	$E3m^3$	$>10^5$	10^5	1.5×10^9	15
	Thickness	m	>1	1	100	5
	Porosity	%	>3	3	30	5
Pilot Properties	Perm-Thick	tonnes/d/w	>30	50	300	5
	Storage Efficiency	%	>0	0	100	5
	CO_2 Gross Utiliz.	tonnes/bbl	<3	3	0.1	20
	CO_2 Net Utiliz.	tonnes/bbl	<3	3	0.1	1
	Oil Process. Rate	boe/d/w	>1	1	250	20
	Water Oil Ratio	m^3/bbl	<100	100	0	10
	Total					**100**

Results

The dimensionless curves previously discussed were either drawn as straight lines using the high and low value of each reservoir property which were deemed to be necessary for commercial exploitation (Appendix 1). In three cases logarithmic coordinates were used in order to group the larger property values into a tighter spread. The weights were chosen to reflect the importance of each property to contributing to a commercial project. Scores for the Alberta pilots and commercial operations (out of 100) ranged from the 30s to the low 70s (see Table 3). The two commercial project scores from Weyburn and Joffre Viking, essentially, encompassed the pilot scores with Weyburn scoring at the high end and Joffre Viking at the low end. The Joffre Viking scored lower because it was a smaller pool and had a much lower oil processing rate compared to Weyburn. All the pilots had adequate permeability and thickness as indicated by the maximum CO_2 injection rates expressed as the Permeability – Thickness Factor. The maximum injection rates for the large reefs and Pembina exceeded 100 tonnes of CO_2/day/well. In contrast, one commercial project, the Joffre Viking, had an average CO_2 injection rate of 36 tonnes/day/well. However, this was not a maximum injection rate and depended on the CO_2 supply availability and injection strategy. Contrast this with the other commercial project at Weyburn where injection of 200 tonnes CO_2/day/well was common. The Injection Storage Efficiency, dependent on the % of water injected in the WAG process favored the vertical flood pools (Zama and Redwater) although Pembina was also highly rated in this area. Two pinnacles at Zama scored the highest (G2G) and (Z3Z). The Z3Z pinnacle score was significantly highly than the other pilots. It was not a typical pilot because it had been used to store acid gas from the nearby gas processing plant to meet H_2S emission requirements and was over pressured. Consequently, when it was commissioned as a CO_2 injection pilot, it had essentially undergone a soak period from the prior disposal of the acid gas. For this reason the pilot actually produced more CO_2 than was injected during the pilot stage and showed a negative net CO_2 utilization factor. The cumulative Oil Processing Rate at 200 bbl/day was nearly an order of magnitude higher than the larger reefs and the WOR was extremely low due to the fact that it had never been waterflooded and aquifer support was weak. However, the Oil Processing Rates of the large carbonate reefs were similar to one of the two commercial projects scored, the Joffre Viking. The commercial Weyburn project had an oil processing rate twice that of the large Alberta reefs. The G2G pinnacle had a high score which ranked closely with the larger reefs from the Swan Hills area, but also had the second lowest WOR probably for the same reasons. These scores for the pinnacle reefs would have been even higher if the potential for recovering incremental oil from other pinnacles had been taken account of in terms of the ROIP available. In contrast, pinnacle F which had been waterflooded, was only producing water (dewatering stage) even though CO_2 was being injected. The F pool had a very low score but the reason for this is that it was at an early stage of CO_2 flooding. Consequently, it also failed the critical threshold for the Oil Processing Rate. The four large Devonian reefs (Swan Hills, South Swan Hills, Judy Creek and Redwater) all scored in the 50s to low 60s, and their score was affected by higher WORs, and lower incremental Oil Processing Rates. The CO_2 gross utilization factors, discounting the Zama Z3Z which is an anomaly, were similar for the higher scoring pools, ranging from 0.7 to 1.4 tonnes of CO_2 injected per bbl of oil produced (13 to 26 mcf/bbl). The Pembina Cardium pilot exhibited a much higher CO_2 utilization. Commercial projects are expected to average around 0.3 tonnes/bbl (5 to 6 mcf) of purchase (net utilization) CO_2 with double that for total CO_2 injected (gross utilization which includes recycle). This is seen in the Joffre Viking and Weyburn data in Table 3. Notably, the pilot results are much higher but as discussed before, the HCPV of CO_2 injected was less than half that expected for a commercial project and these values will drop as the HCPV increases.

Based on the scoring results, the Zama pinnacles are attractive targets if the individual pinnacles which would provide similar results to the Z3Z and G2G pinnacles can be identified. The results for the F pinnacle are inconclusive since it is still in a dewatering stage. All the large reefs are attractive as standalone targets but would be even more so when their relative locations are considered. For example, in traversing North to South, Swan Hills, South Swan Hills, Judy Creek and Carson Creek are all clumped together with an OOIP approaching that of Pembina Cardium. Redwater is in a unique situation being the third largest oil pool in Canada and sitting next to Fort Saskatchewan, one of the largest emission sites in Alberta. Although the Pembina Cardium is the largest oil pool in Canada, it scored the lowest of the large pools with the lowest oil processing rate and the highest CO_2 gross utilization factor and is considered a distant third in the scoring classes, the pinnacle reefs and the large carbonate reefs being first and second. Possibly the Pembina pilot performed poorly, because of the choice of site, being in a poorer part of the Pembina Cardium pool. Notably, a second pilot was developed using horizontal wells which would help address the relative thinness of the Cardium pool but was not analyzed here. This possibly emphasizes the role new technology such as horizontal wells can play in developing further these large depleted reservoirs in the future. The extensive use of horizontal wells in Weyburn may account partly for the higher oil processing rates compared to the Joffre Viking. The only pilot that scored poorly was the Enchant Arcs pool having a score less than 40 due to low ROIP, oil processing rates and high gross CO_2 utilization factors. This pilot had an odd configuration being only confined by 3 producers and did not see any significant enhanced oil production. This pilot was a failure. It remains to be seen whether other similar pools in this area could perform better or that the use of horizontal wells might make a difference.

Table 3: Property values, dimensionless values, weights and scores for the Alberta pilots

Scoring for Pilot CO2_EOR projects in Alberta (May 21, 2013): SUM(Utility x Weight) = Scores											
Property	Swan H	SSH	Judy C	Enchant	Redwater	Zama F	ZamaG2G	Zama Z3Z	Pembina	Joffre Viking	Weyburn
API	4.15	4.15	4.15	0.9	3.05	2.85	3.05	3.7	3.5	3.45	1.55
Pi/MMP	0.46	1.14	0.52	0.6	0.2	0.28	0.34	0.58	2	0	0.24
Viscosity	1.86	1.86	1.86	0.24	1.72	1.68	1.72	1.82	1.8	1.8	1.88
Soil (initial)	4.35	4.6	4.6	4.3	3.9	4.8	4.8	4.65	4.65	3.15	3.2
ROIP	12.75	10.65	10.2	3.9	10.05	1.95	2.4	1.05	14.55	6.75	11.4
Thick	1.8	1.15	1.25	0.47	2.55	2.55	1.7	2.1	0.365	0.1	1.25
Porosity	0.9	1	1.1	2	0.6	0.75	0.9	1	1.65	1.85	3.15
Perm-Thickness factor	2.35	3	3.4	0.9	4.2	0.2	2.8	2.8	1	0	3
Inj. Storage Efficiency	1.6	0.75	0.8	3	5	5	5	5	4.8	1.15	2.15
CO2 Gross Utilization factor	11.6	13.8	15.8	4.4	13.2	0	15.4	18.8	4.4	16.6	17.4
CO2 Net Utilization factor	0.65	0.72	0.85	0.22	0.85	0	0.94	1	0.31	0.91	0.94
Inc. oil processing Rate	10.8	10	13.6	8	12	0	16.8	19.2	6.4	10.8	15.6
WOR: prod. Water/Oil Ratio	1.1	2.8	2	4.2	2.9	0	6.7	10	4.7	4.7	5.5
SCORES	**54.37**	**55.62**	**60.13**	**33.13**	**60.22**	**20.06**	**62.55**	**71.7**	**50.13**	**51.26**	**67.26**
Scoring for Pilot CO2_EOR projects in Alberta (May 21, 2013): Utility (ranges 0 to 1)											
Property	Swan H	SSH	Judy C	Enchant	Redwater	Zama F	ZamaG2G	Zama Z3Z	Pembina	Joffre Viking	Weyburn
API	0.83	0.83	0.83	0.18	0.61	0.57	0.61	0.74	0.7	0.69	0.31
Pi/MMP	0.23	0.57	0.26	0.3	0.1	0.14	0.17	0.29	1	0	0.12
Viscosity	0.93	0.93	0.93	0.12	0.86	0.84	0.86	0.91	0.9	0.9	0.94
Soil (initial)	0.87	0.92	0.92	0.86	0.78	0.96	0.96	0.93	0.93	0.63	0.64
ROIP	0.85	0.71	0.68	0.26	0.67	0.13	0.16	0.07	0.97	0.45	0.76
Thick	0.36	0.23	0.25	0.094	0.51	0.51	0.34	0.42	0.073	0.02	0.25
Porosity	0.18	0.2	0.22	0.4	0.12	0.15	0.18	0.2	0.33	0.37	0.63
Perm-Thickness factor	0.47	0.6	0.68	0.18	0.84	0.04	0.56	0.56	0.2	0	0.6
Inj. Storage Efficiency	0.32	0.15	0.16	0.6	1	1	1	1	0.96	0.23	0.43
CO2 Gross Utilization factor	0.58	0.69	0.79	0.22	0.66	0	0.77	0.94	0.22	0.83	0.87
CO2 Net Utilization factor	0.65	0.72	0.85	0.22	0.85	0	0.94	1	0.31	0.91	0.94
Inc. oil processing Rate	0.54	0.5	0.68	0.4	0.6	0	0.84	0.96	0.32	0.54	0.78
WOR: prod. Water/Oil Ratio	0.11	0.28	0.2	0.42	0.29	0	0.67	1	0.47	0.47	0.55
Scoring for Pilot CO2_EOR projects in Alberta (May 21, 2013): Pilot & Commercial Values for Properties											
Property	Swan H	SSH	Judy C	Enchant	Redwater	Zama F	ZamaG2G	Zama Z3Z	Pembina	Joffre Viking	Weyburn
API (degrees)	41	41	41	26	36	35	36	39	38	38	29
Pi/MMP (ratio)	0.96	1.2	0.98	1.08	0.87	0.9	0.92	1.02	1.5	0.64	0.88
Viscosity (cp)	3.65	3.65	3.69	48.5	7.36	8.56	7.36	4.76	5.48	5.41	3.2
Soil (initial) (fraction)	0.81	0.84	0.84	0.8	0.75	0.87	0.87	0.85	0.85	0.64	0.65
OOIP - Cum Prod. (E3m3)	315,780	88,292	68,076	1,153	63,848	346	440	190	1,282,004	7,421	153,500
Thick (m)	36	23	25	9.42	51	51	34	42	7.25	2.73	25
Porosity (%)	8	8.4	9	14	6.5	7	8	8.6	12	13	20
Perm-Thickness factor (t/d/w)	167	199	221	95	260	60	190	190	100	36	200
Inj. Storage Efficiency (%)	31.8	14.7	15.4	60	100	100	100	100	93.9	23	43
CO2 Gross Utilization (t/bbl)	1.36	0.98	0.7	2.37	1.06	657	0.73	0.24	2.35	0.59	0.47
CO2 Net Utilization (t/bbl)	1.12	0.93	0.52	2.37	0.52	657	0.24	-0.13	2.1	0.35	0.27
Inc. oil process. Rate (bbl/d/w)	20	15	36	9	27	0.04	105	206	6	20	72
WOR: prod. Water/Oil (m3/bbl	36.5	7.8	15	2.2	6.9	1077	0.21	0.01	1.2	1.27	0.64

Conclusions

This methodology was developed to rank conventional CO_2 – EOR prospects on a technological basis. One might say that it doesn't fit huff and puff, but it could easily be adapted to it, if necessary, by defining a criterium for huff and puff. A different view would be that the criteria already chosen would effectively evaluate that option (e.g. oil processing rate) but that the weights have to be re-evaluated. Similar arguments could be made for multistage fracing, horizontal wells and ROZs. Of course, the lack of data for ROZs would hamper including them in such an analysis. Tight oil is in a different category, as it is being commercially developed in spite of CO_2 – EOR opportunities. Tight oil would be ranked against the top CO_2 – EOR prospects under economics. However, secondary recovery in tight oil might open up new CO_2 – EOR opportunities. The other opportunity is the integration of CO_2 – EOR with CCS. For the scoring methodology developed here, one criterium was used to be sensitive to CCS potential but was weighted low. Its weighting could easily be increased and other criteria weights decreased if more emphasis was wanted on CCS. At the end of the day, the final decision would still have to be made from economic evaluation.

II. ECONOMICS

Standard risk management deals with scheduling and cost uncertainty, with changes in scheduling affecting the costs. The uncertainties are huge in both CO_2 – EOR and CCS. In this report, the biggest hurdle identified was the cost for a sustained CO_2 supply to the field gate. It was not considered in the technology example. However, an oil pool, having passed the technology assessment as described above, would then need to be matched to a CO_2 supply.

Risk management depends a lot on expert opinion, particularly in areas of endeavor where few commercial examples exist such as CCS. Where such large uncertainties exist, often a netback calculation is a good starting point to try and get agreement from expert opinions. We think that the affordable price of CO_2 is an area where considerable disagreement exists. Below, we present a netback calculation approach that we think will allow agreement to be reached between groups which have different drivers in their corporate strategies.

Affordable Cost of CO_2

The price of CO_2, an oil and gas company can afford to pay is based on the purity of the CO_2, the price of oil, the proximity of the CO_2 source to the oil pool, the productivity of the oil pool and the pool size (commonly referred as the 5 Ps). The economics of CO_2 are very complex with high capital costs up front for the oil and gas producer before any incremental oil is produced. This is similar to an electrical utility. However, the two conduct their businesses completely differently. The utility produces a constant amount of electricity and by default CO_2 and wants a guaranteed rate of return for his products which is tied to the price of electricity. The utility does not regard the CO_2 as garbage but as a commodity. The oil and gas company has no guarantee of the amount of enhanced oil recovery that will be produced from the reservoir. That is the oil and gas company cannot guarantee that it can use a continuous fixed amount of CO_2 and therefore is reluctant to accept a utility type fixed amount contract. In fact the oil and gas company regards the CO_2 as a waste product. Consequently, it is very difficult for the two sides to negotiate a contract which reflects the risks of their respective businesses. This can be solved by a third party building a "backbone pipeline" for the CO_2 where he guarantees to purchase all the CO_2 the utility can produce and offers to sell the CO_2 to the oil and gas company on an incremental nature based on the success or failure of the CO_2-EOR project. If this can be arranged satisfactorily, then a simple economics case can be evaluated as shown below, where the price of CO_2 refers to pure CO_2 delivered at pressure to the oil field gate.

Angevine and Hrytzak-Lieffers (2007) used a netback calculation to analyze the cost of a CO_2 backbone pipeline for Alberta. Kruuskraa and Ferguson (2008) used a similar netback calculation (referred to here as DOE/NETL) to calculate EOR economic margins for EOR projects based on a long term contract with a CO_2 supplier. They used data based on U.S. onshore EOR. They assumed production costs, CO_2 costs and carbon offset as:

- $2.38 Mcf ($45/tonne CO_2) purchase and $0.70 ($13/tonne) for recycle, which ranges above the upper limit for Canadian oil and gas producers based on our current survey
- 5 to 6 Mcf (0.26 to 0.32 metric tonnes) of purchased CO_2, and 5 to 10 mcf (0.26 to 0.52 metric tonnes) of recycled CO_2 during the latter stages of the CO_2-EOR process per barrel of oil.
- Production costs were split into externalities (such as royalties and taxes), capital (expressed as a depreciation), operations and maintenance (such as wells and leases)
- They noted that “considerable reservoir-specific variations exist around the cost and economic margin values used.

Table 4: Comparison of DOE/NETL methodology (where the CO_2 cost is a fixed dollar value and the economic margin for the oil producer floats) to the ADB methodology (where the economic margin is a fixed percent and the affordable CO_2 cost floats).

Costs/Profit	**Calculation Method**	DOE/NETL onshore	ADB onshore	DOE/NETL onshore	ADB onshore
Assumed Oil Price ($/bbl)		***$70***	***$70***	***$100***	***$100***
Gravity/Basis Differential, Royalties and Production Taxes		($15)	($15)	($15)	($15)
Capital Costs (Depreciation)		($5 to $10)	($7.50)	($5 to $10)	($7.50)
Well/Lease O&M		($10 to $15)	($12)	($10 to $15)	($12)
Total Production Costs ($/bbl)		***($30 to $40)***	***($34.50)***	***($30 to $40)***	***($34.50)***
CO2 Costs ($/bbl oil)		($15)	($7.50)	($15)	($25.50)
Total Fixed Costs ($/bbl oil)		***($45 to $55)***	***($42)***	***($45 to $55)***	***($60)***
Economic margin ($/bbl oil)		***$25 to $15***	***$28***	***$55 to $45***	***$40***
Available for CO2 ($/tonne CO2) at Net Util. = 0.32t/bbl (6mcf/bbl)		***Fixed =($46.88)***	***Affordable =($23.44)***	***Fixed =($46.88)***	***Affordable =($79.68)***

In another study, the Asian Development Bank (2012, ADB) used the DOE/NETL approach as a basis to calculate an affordable cost of CO_2. The comparison between the two methods is shown in Table 4. Total production costs for DOE/NETL varied from $30 to $40 while ADB used the DOE/NETL average of $34.50. DOE/NETL assumed the cost of CO_2 was $15/bbl of oil produced while ADB assumed the affordable cost of CO_2 was the difference between the selling price of a barrel of oil and the sum of the total production costs plus the economic margin for the oil company (40% of the selling price of a barrel of oil). DOE/NETL calculated the oil company’s economic margin as the difference between selling price of a barrel of oil and the total fixed costs (production costs and cost of CO_2). It can be seen from Table 4 that the total fixed costs for the DOE/NETL calculation are $45 to $55/bbl oil independent of the selling price of a barrel of oil while ADB fixed costs increase as the selling price increases from $42 to $60 as the price of a barrel of oil increases from $70 to $100.

Profits for the DOE/NETL calculation are $15 to $25/bbl for $70 oil based on a fixed CO_2 price of $47/tonne ($2.54/mcf), compared to the ADB calculation of $28/bbl profit based on affordable CO_2 price of $23/tonne ($1.24/mcf). For $100 oil; profits for the DOE/NETL calculation are $45 to $55/bbl based on a fixed CO_2

price of \$47/tonne ((\$2.54/mcf), compared to the ADB calculation of \$40 profit based on an affordable CO_2 price of \$80/tonne (\$4.31/mcf).

This simple calculation can be used to scale the cost of CO_2 to the price of oil by assuming net and gross utility factors for CO_2 per barrel of oil where net is the amount of purchased CO_2 and gross is the sum of the net CO_2 and recycled CO_2. Also, the government, capital and operating costs may vary depending on the country and existing infrastructure; but these can be easily changed if known, as can the oil and gas company's profits which are normally based on a high risk rate of return in a more detailed economic analysis. Simple graphs can be drawn to show the affordable price of CO_2 based on the price of oil. An example of such an approach is shown in Figure 22 based on the ADB analysis presented in Table 4. If such an analysis shows promise, then a more rigorous economic analysis should follow. Such a procedure can be used to further rank projects that passed the previous reservoir screening and scoring assessments.

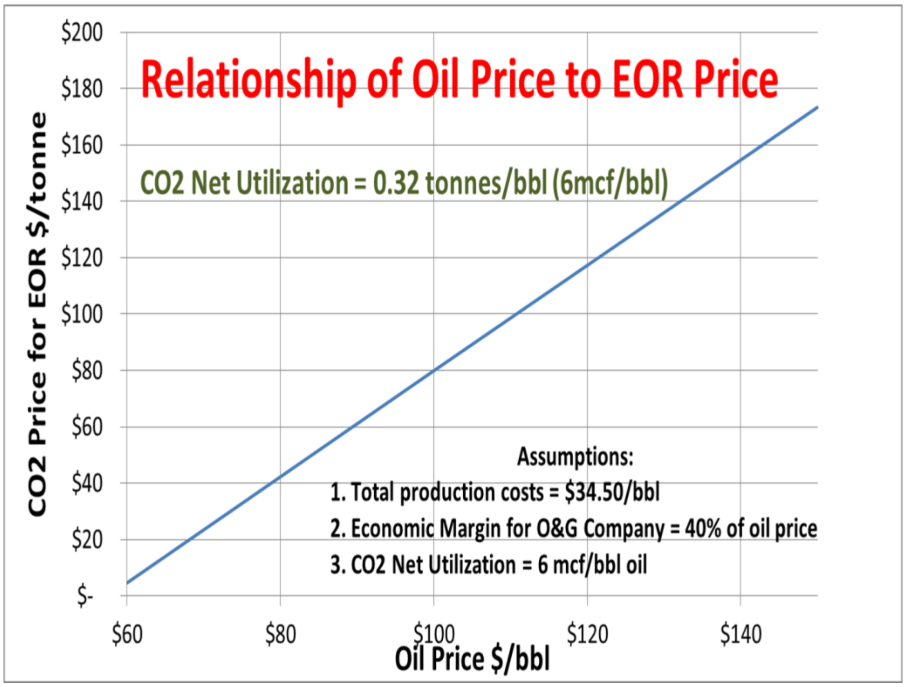

Figure 22: Affordable price of CO_2 as a function of oil price in netback calculation

Conclusions

Once an acceptable cost for CO_2 is agreed upon, the magnitude of other uncertainties will shrink and decisions can be made which will result in a much more robust management plan. As previously pointed out, the cancellation of the Pioneer project was largely due to being unable to get agreement on an acceptable cost of CO_2 between the seller and the buyer. Using our approach, different groups will calculate different affordable prices for CO_2 and agreement may or may not be reached between parties. If needed at this point, having a firm knowledge of the gaps in CO_2 price, policy can play a role to make a long term supply of CO_2 attractive to all parties. The question from a government policy perspective is whether it is more appropriate to base economic evaluation on full life cycle economics or incremental project economics.

III. POLICY

Policy uncertainty in risk management can be one of the largest risks. Development of policy based on maximization of the oil resource recovery can play a large role in the attractiveness of CO_2 – EOR projects. A number of incentives were discussed in this report. We think that the biggest opportunity is in the linking of CO_2 – EOR with CCS as illustrated in Figure 23. On this figure the price of oil is shown as colored bands from $50 to $125/bbl. The price of CO_2 appears on the horizontal axis, and cumulative amounts of oil produced and CO_2 stored at these prices appear on the vertical axis. The oil produced and the CO_2 stored (sequestered) bear a simple relationship; for every barrel of oil produced, approximately 1/3 of a tonne of CO_2 is stored in the depleted reservoir that the oil is being produced from (this is the same number used in Figure 22, labeled CO_2 net utilization). The difference between the two figures is that Figure 23 has the oil price as a band (2 D) rather than a line (1D) as it appears in Figure 22; reflecting the uncertainty in the relationships between oil price, CO_2 price, oil production costs and oil production.

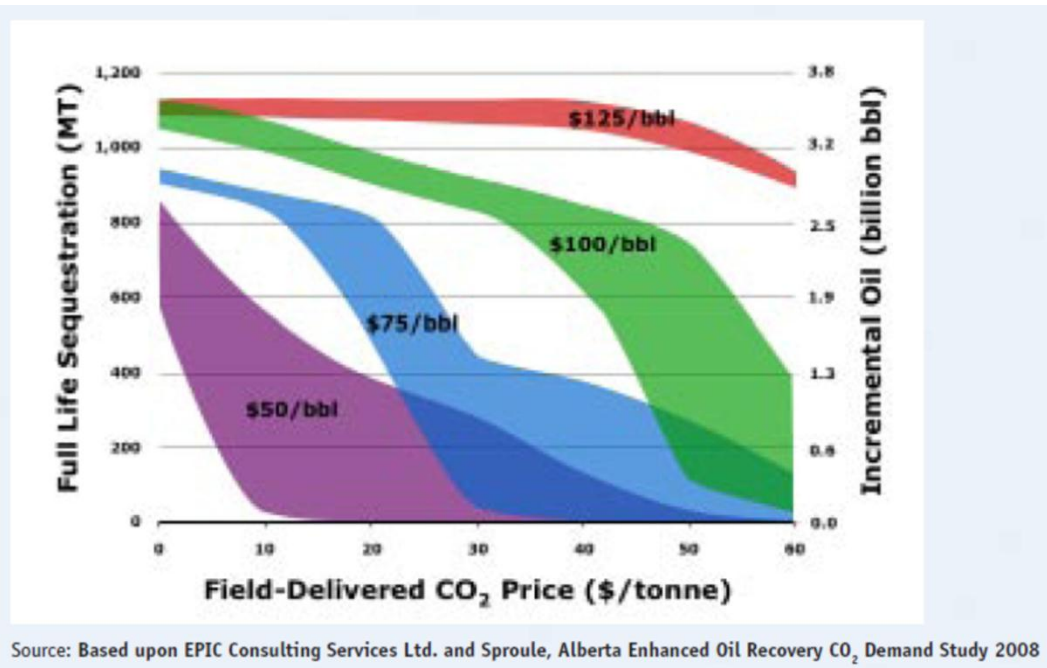

Figure 23: CO_2-EOR incremental recovery and associated CO_2 storage potential in Alberta (after Alberta Carbon Capture and Storage Council, 2009)

Integration of CO_2-EOR and CCS

However, regulatory setbacks exist for crediting CO_2 storage with respect to CO_2 storage linked to EOR. A CO_2-EOR credit system needs to be set up so that there is an incentive to encourage this. A simple scenario could be similar to the following. A different viewpoint of CCS is that it can be initially an enabler for CO_2-EOR by giving CO_2-EOR credits for the CO_2 used for EOR as it is injected into the reservoir. A simple analogy would be to consider the EOR reservoir as a bank. All the purchased CO_2 is injected into the reservoir (goes into a savings account in the bank) and during the EOR process, excess CO_2 breaks through and is produced to surface where it can be recycled back into the reservoir or emitted to the atmosphere (a short term CO_2 loan which is paid back in the former case). At the end of the project the oil pool is either abandoned (remaining CO_2 stays in the savings account in the bank) or blown down and the CO_2 is resold (much of the CO_2 is removed from savings account in the bank with only the residual CO_2 remaining). Loss of CO_2 to the atmosphere during the recycling would have to be accounted for (by appropriate decrease in the value of the savings account). By granting the CO_2-EOR credits recognition early and establishing a market for them during the process, it would help defray the large capital costs encountered early in the life of a CO_2-EOR project. CCS can also be used as a means to store excess CO_2 while the EOR scheme is ramping up by storing the CO_2 in an approved CCS reservoir (e.g. a saline aquifer). This helps to allow for a steady CO_2 supply while accounting for a fluctuating CO_2 demand by the EOR operations. At the end of the CO_2-EOR project, a case could be made for the stored CO_2 in the EOR reservoir to be transferred to an offset CCS credit, which in effect allows the CO_2-EOR project to become an enabler for CCS.

Conclusions

Obviously, the assumptions in the construction of Figure 23 would play an important role in the risk management planning. The assurance of a policy such as time sensitive crediting of CO_2 – EOR would lower the risk of a commercial CO_2 – EOR project and make it financially more attractive. This would be comparable to incentives that other types of oil recovery operations have available to assist in their justification (e.g. oil sands).

IV RISK MANAGEMENT FRAMEWORK

A potential for a CO_2 – EOR project to evolve has been discussed in a three step scenario. In step 1, under technology, a tool was developed for technically scoring CO_2 – EOR oil pool opportunities. Those oil pools that have attractive scores should be passed onto the "hunt" for an affordable CO_2 supply by using a netback calculation assessment as described under economic considerations in Step 2. If a price gap exists between the CO_2 supplier and the CO_2-EOR operator, then policy can play a major role. In step 3, under policy, consideration of different types of incentives led to proposing a mechanism for early crediting of CO_2 – EOR for storing CO_2 that might be a "win-win" situation for CO_2 –EOR and CCS. However, these three steps form only one potential pathway of many. These discussions under Technology, Economics and Policy contain novel examples of developing deterministic tools that will fit into a risk management structure and can be used to develop a risk management plan.

A good approach would be to set up a risk management framework directed at evaluating CO_2 – EOR commercial projects from the information that is publically and privately available. Risks or uncertainties are identified, assessed and addressed in a deterministic manner in the initial project phases followed by integrated probabilistic risk analysis based on expert opinion and Monte Carlo statistical methodology to define project reserves and sensitivities including reputation, environment and safety. Uncertainties around technologies, economics and policy are included. The exact nature of the risk management framework depends on the goal of the project. In fact there may be several projects with different goals needing individual risk management plans for their assessment and execution. It is beyond the scope of this report to formulate a comprehensive plan to do this. The long term purpose of such a risk management framework would be to evaluate the potential for CO_2 – EOR commercial projects in Alberta on a quantitative basis by identifying and quantifying important risks, planning appropriate responses to them if required and justifying addition of them to Alberta oil reserves.

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Conversion Factors

ft	x 0.3048*	= m
m	x 3.281	= ft
ft^3	x 0.02831685	= m^3
m^3	x 35.315	=ft^3
^oAPI	141.5/(131.5 + ^{o}API)	= g/cm^3
^oF	^{o}(F-32)/1.8	= ^{o}C
cp	0.001*	= Pa.s
psi	x 0.0068947	=MPa
MPa	x 145.04	= psi
md	x 9.869233 x 10^{-4}	=$(um)^2$
darcy	x 9.869233 x 10^{-13}	= m^2
bbl	x 0.1590	= m^3
m^3	x 6.290	= bbl
mcf	x 0.05394 3	= metric ton CO_2 = tonne CO_2 = t_{CO2}
t_{CO2}	x 18.54	= mcf
m^3	x 0.001854	= metric ton CO_2 = tonne CO_2 = t_{CO2}
t_{CO2}	x 539.4	= m^3
acres	x 0.4047	= hectares
hectares	x 2.471	= acres

*Conversion is exact

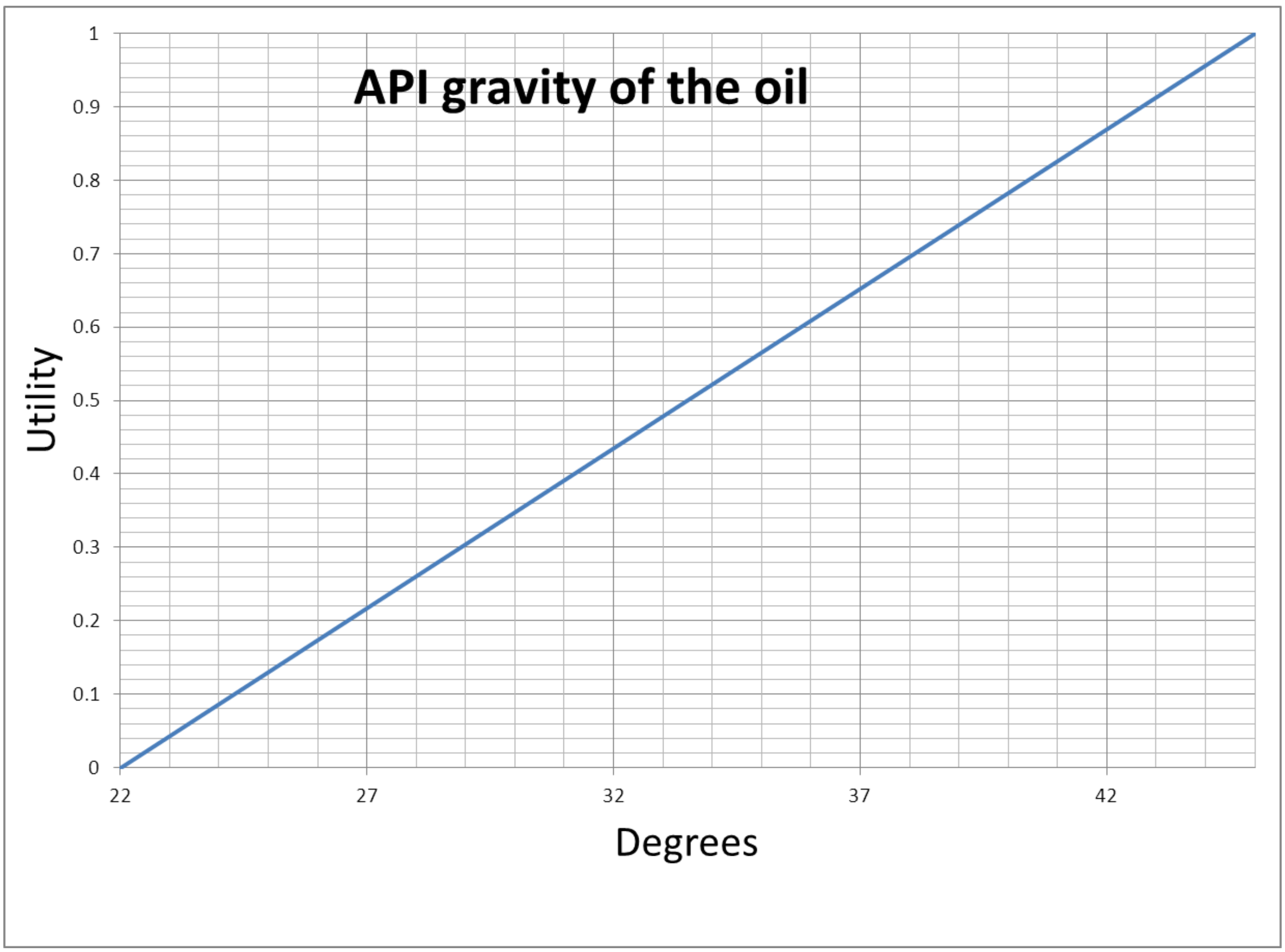
APPENDIX 1

Screening and Scoring Criteria: Construction of the Dimensionless Utility Curves

The selection of a CO_2 EOR site depends on a number of different preferential criteria, once the site has passed the qualifying or screening criteria. Scoring is accomplished by constructing dimensionless curves to evaluate individual preferential criteria and then multiplying the dimensionless curve score (0 - 1) by the weights and summing them to arrive at a score based on 100%.

Fluid Criteria

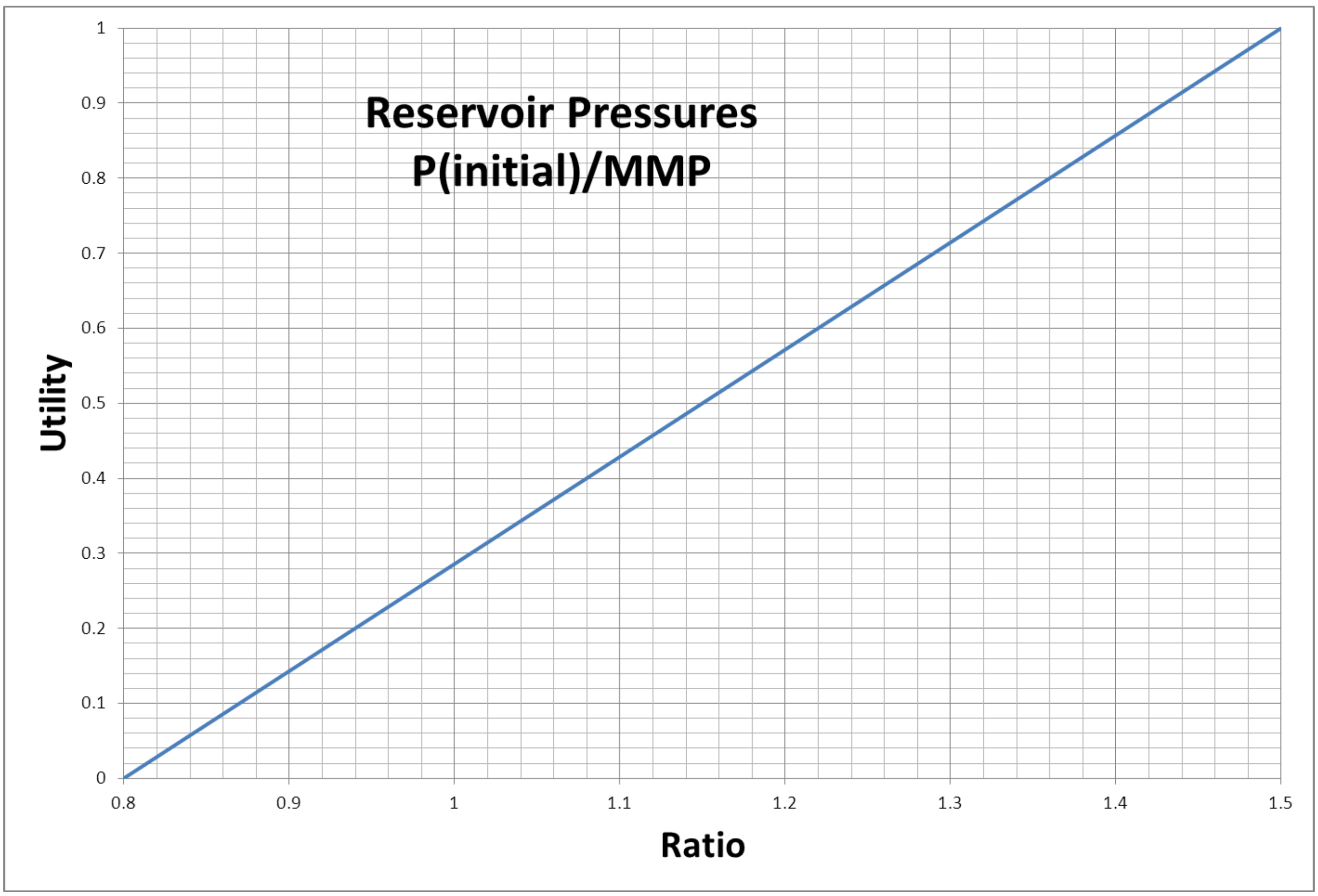
Fluid Properties: API Gravity
API gravity is defined so that a value of 10^o it is equal to a Specific Gravity (SG) of 1. The heavier oils (i.e. $<10^o$) require higher MMP; and because of their higher viscosity, the CO_2 diffuses more slowly into the oil. A hard threshold would be API gravity of 22^o. Only oils greater than this should be considered.



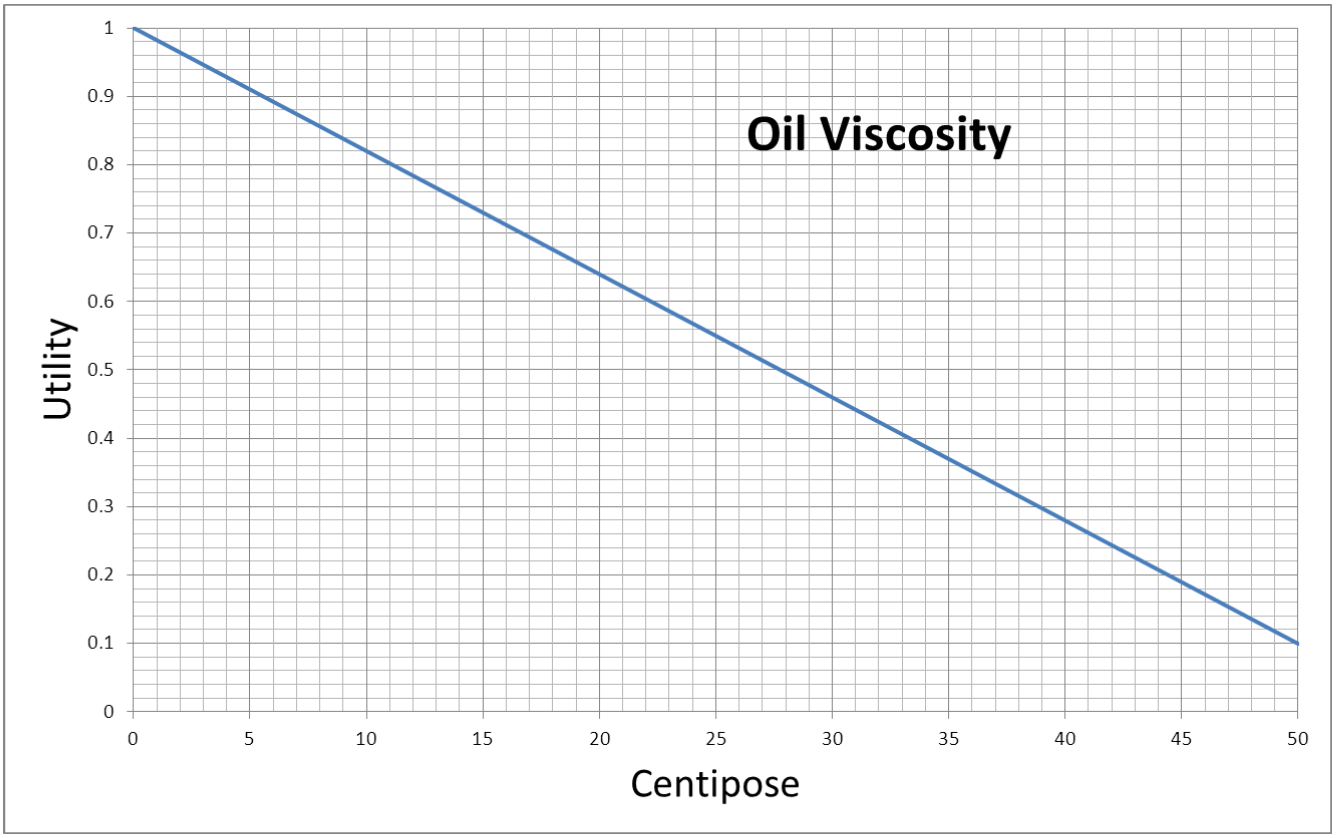
Fluid Properties: P_i/P_{MMP}

Achieving miscibility is critical to optimizing the oil recovery process and depends on a number of factors. The only one which is controlled by the operator of the project is injection pressure. It is desirable to have the injection pressure exceeding the MMP. The injection pressure that can be used depends on the initial reservoir pressure (P_i). P_i is related to depth and the geopressure gradient. Obviously shallow reservoirs such as the oil sands in Alberta would not be candidates for miscible flooding. Pools should be deeper than 2000 ft (600 m) depth which is equivalent to a hydrostatic pressure of 6 MPa (870 psi). Only greater depths should be considered ranging from 600 to 6000 meters.

If data is available for P_i, API gravity, and temperature, a MMP can be calculated and compared to the P_i. A hard minimum threshold would be P_i/MMP of 0.6 (The utility between 0.6 and 0.8 is set equal to zero). Only ratios above that would be considered. If data is not available for P_i, a pressure gradient can be used if known. The IEA (2009) used a gradient of 0.6 psi/ft for their estimates. If hydrostatic pressure is assumed, the gradient would be less, at approximately 0.46 psi/ft.

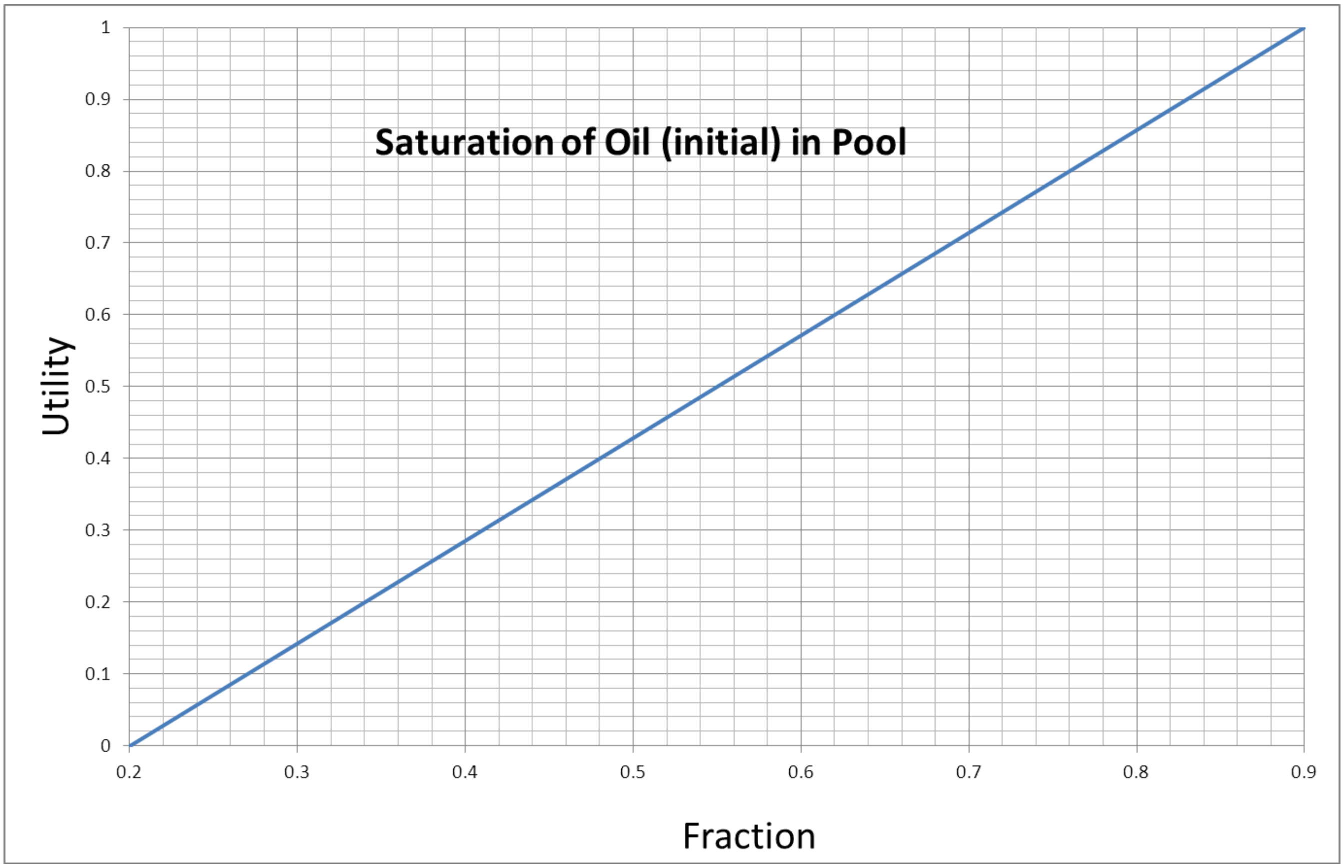


Fluid Properties: Oil viscosity
Viscosity reflects the ease at which the oil will flow. A hard maximum threshold value would be 50 cp. Only oils less than 50 cp should be considered based on Figure 18.



Fluid Properties: Oil Saturation

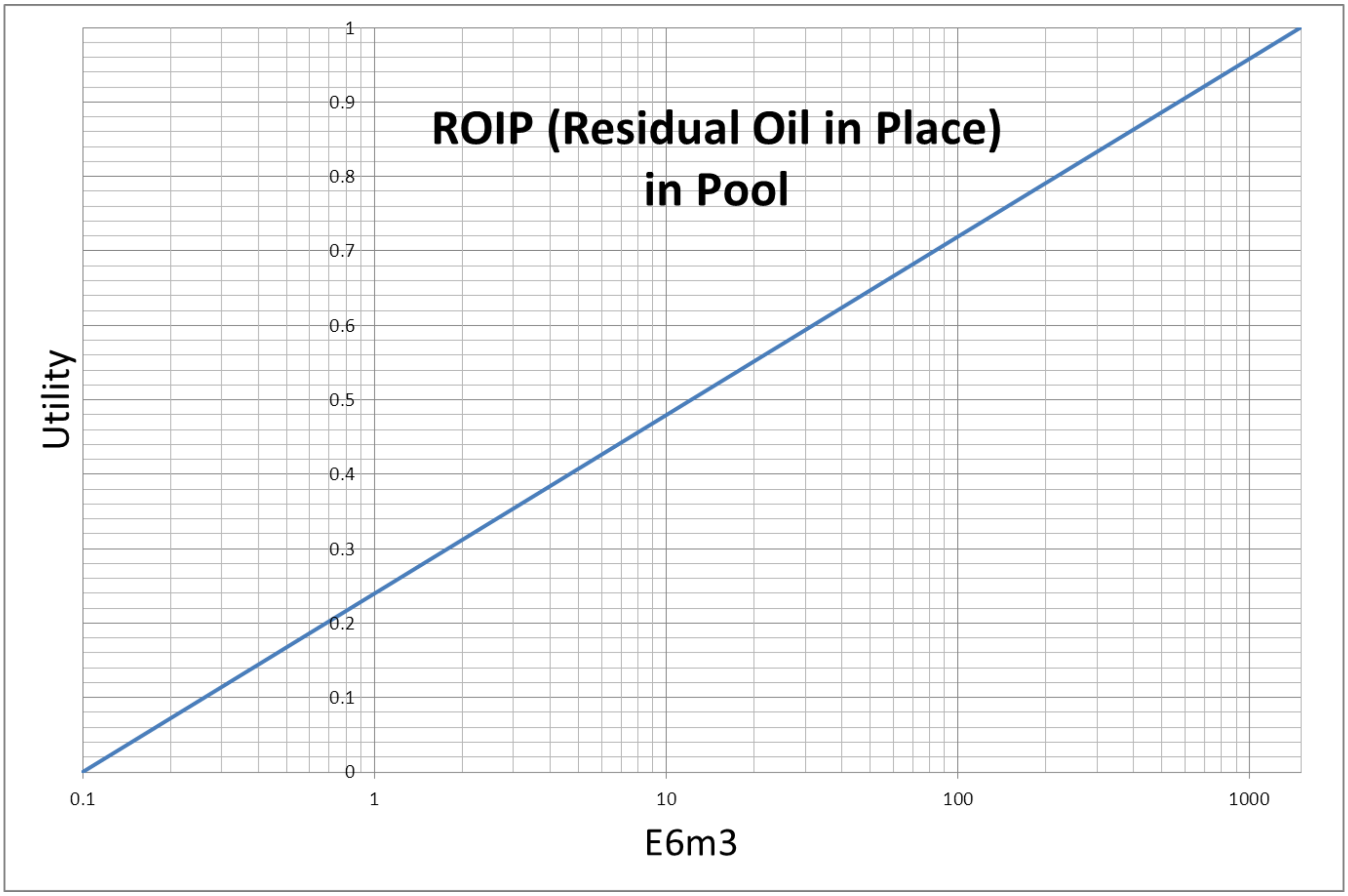
The oil saturation in the pores must be sufficient to be able to mobilize it. A hard minimum threshold value would be 20%. Only oil saturations greater than 20% should be considered. This information is not available easily. Here, it has been replaced by the initial oil saturation, a value easily obtained. Also since, the whole oil pool is being considered, the residual oil saturation would be quite variable across the pool depending on its state of development whereas the initial oil saturation is more uniform.



Reservoir Criteria

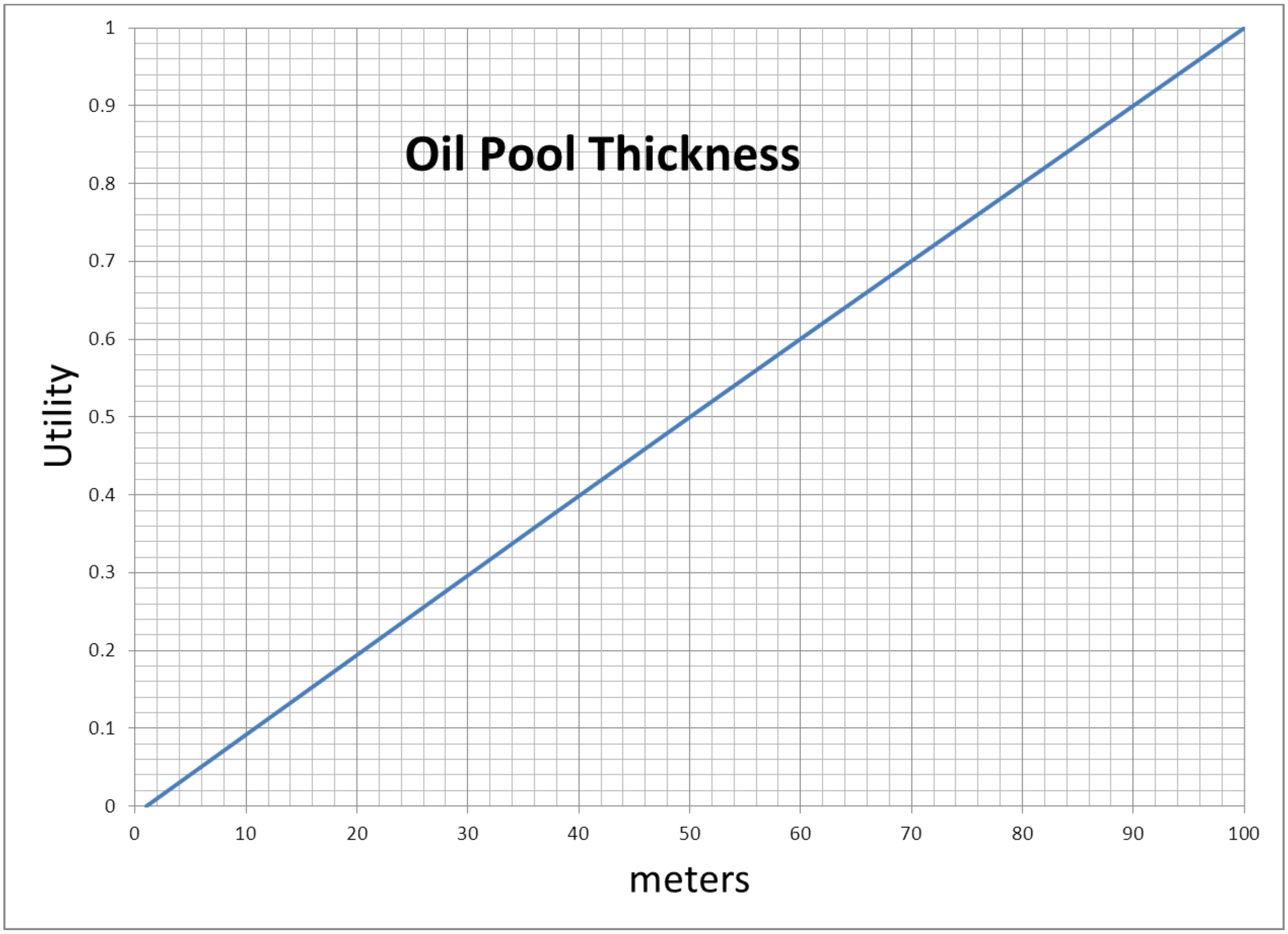
Reservoir Properties: ROIP

There must be sufficient Remaining Oil In Place (ROIP) in the reservoir to make recovery attractive. A hard minimum threshold value would be approximately 1 million bbl or 100,000 m^3. Only oils that have higher ROIP should be considered. Note that a logarithm relationship was used here.



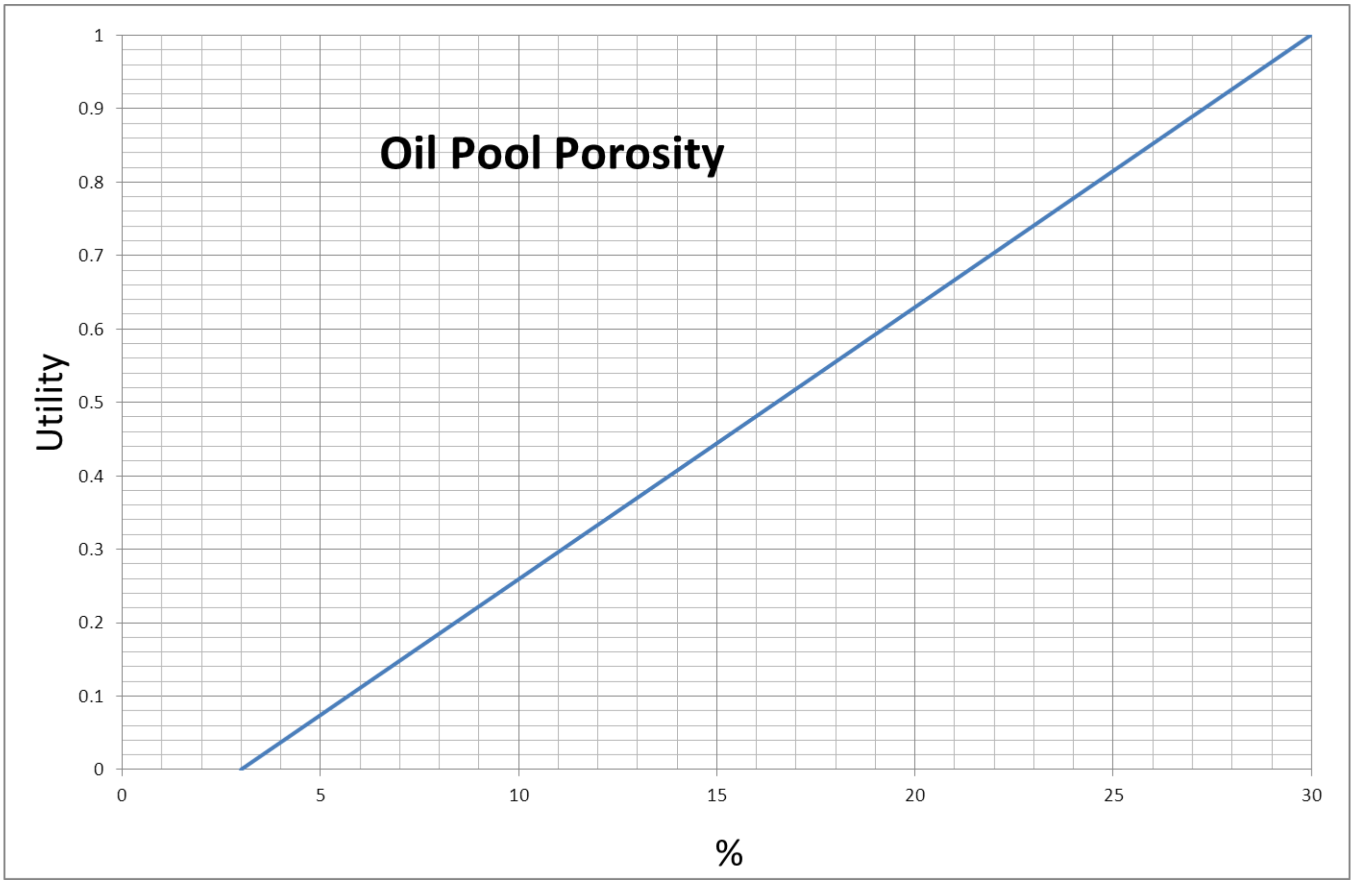
Reservoir Properties: Net thickness

Thinner reservoirs prevent gravity override but thicker reservoirs allow a stable gravity top down displacement. Below a meter thickness neither strategy works. The hard threshold thickness is set at 1 meter. Only reservoir thicknesses above 1 m would be considered.



Reservoir Properties: Porosity

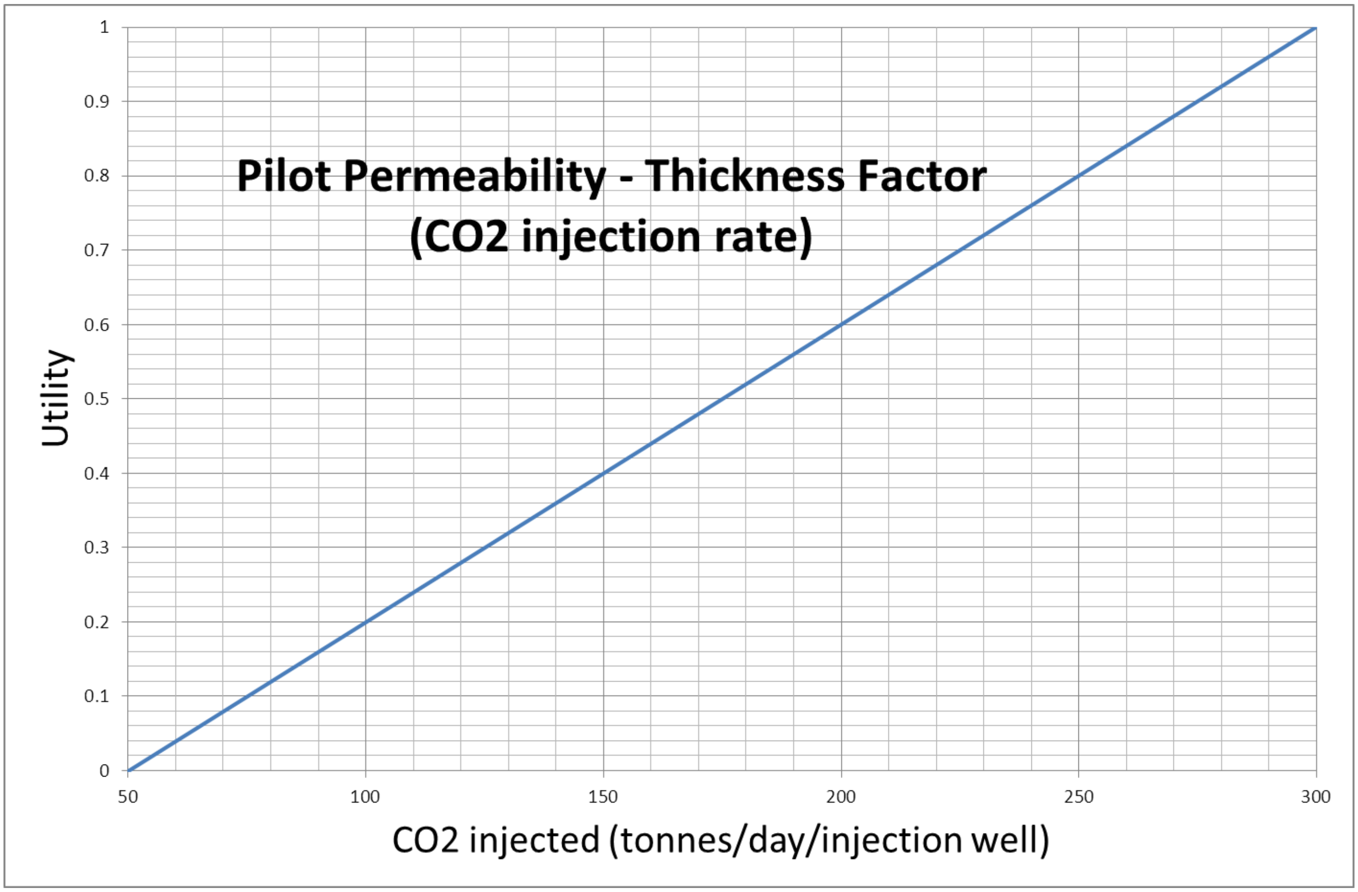
Higher porosities are favored. The hard threshold porosity is 3%. Only reservoir with porosities above 3% would be considered.



Pilot Criteria

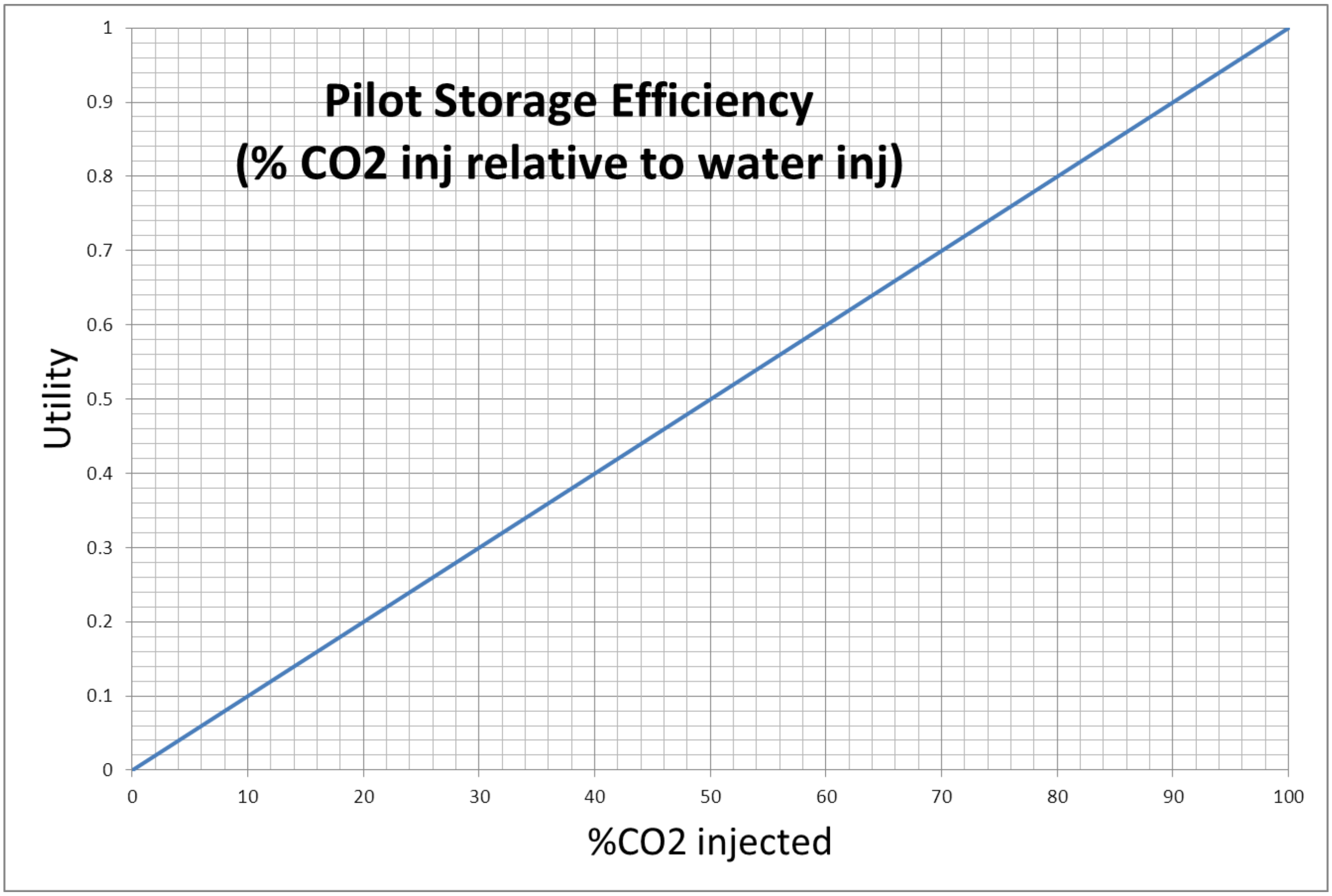
Pilot Properties: Permeability – Thickness Factor

The maximum injection rate for CO_2 was used as it was felt that in order to keep the reservoir above the miscibility pressure and produce oil at reasonable rates, injection rates would be high but limited by not exceeding fracing pressures. The pressure build up would be determined by the permeability and thickness of the reservoir. This implies that the higher the injection pressure, the higher the permeability – thickness product.



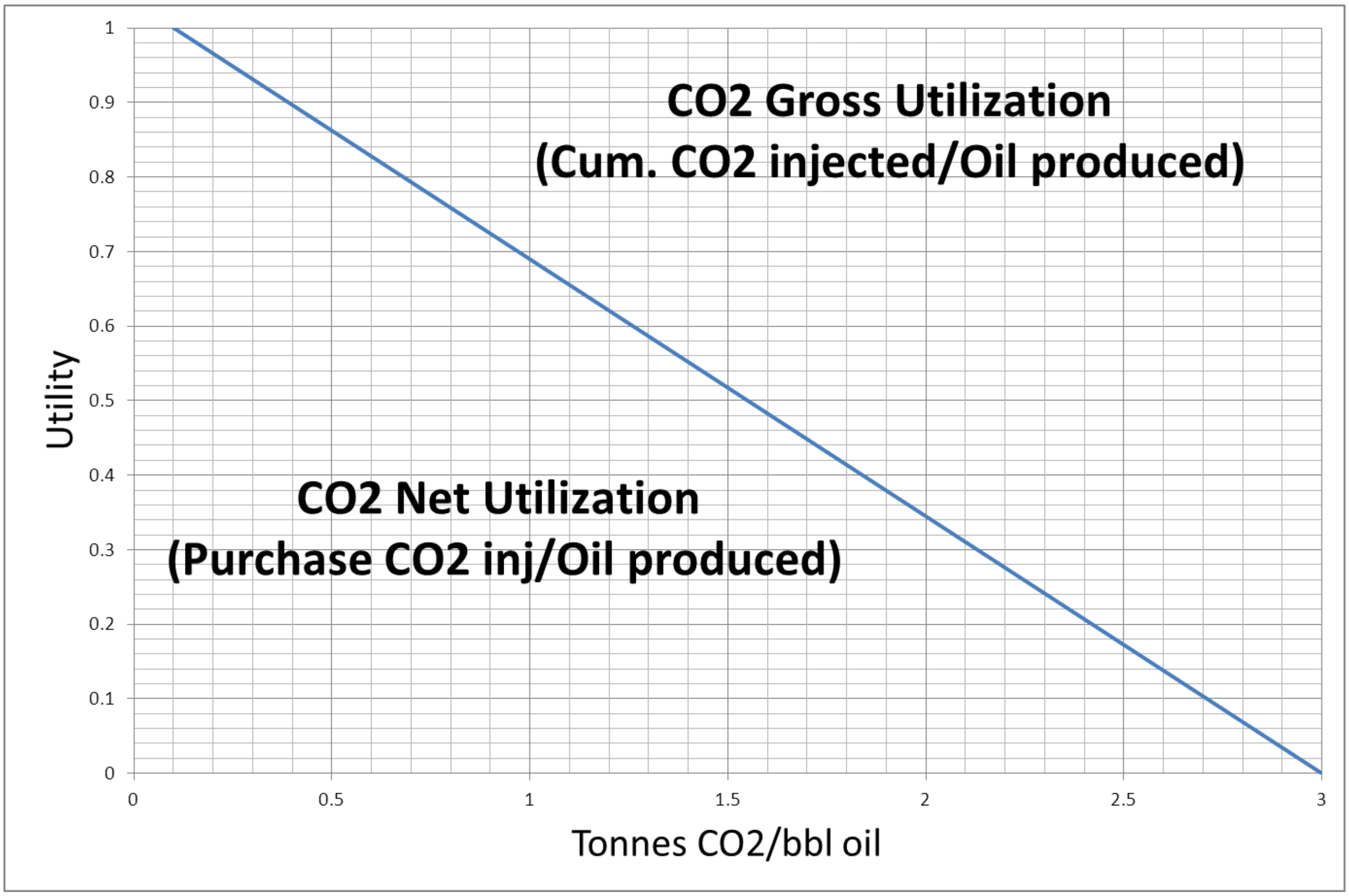
Pilot properties: Injection Storage Efficiency

This is measured by calculation of the % of cumulative CO_2 injected relative to cumulative water + CO_2 injected. If no water is injected then the storage efficiency would be 100% as no additional water would be available to occupy pore space thus isolating that pore space from CO_2 occupancy.



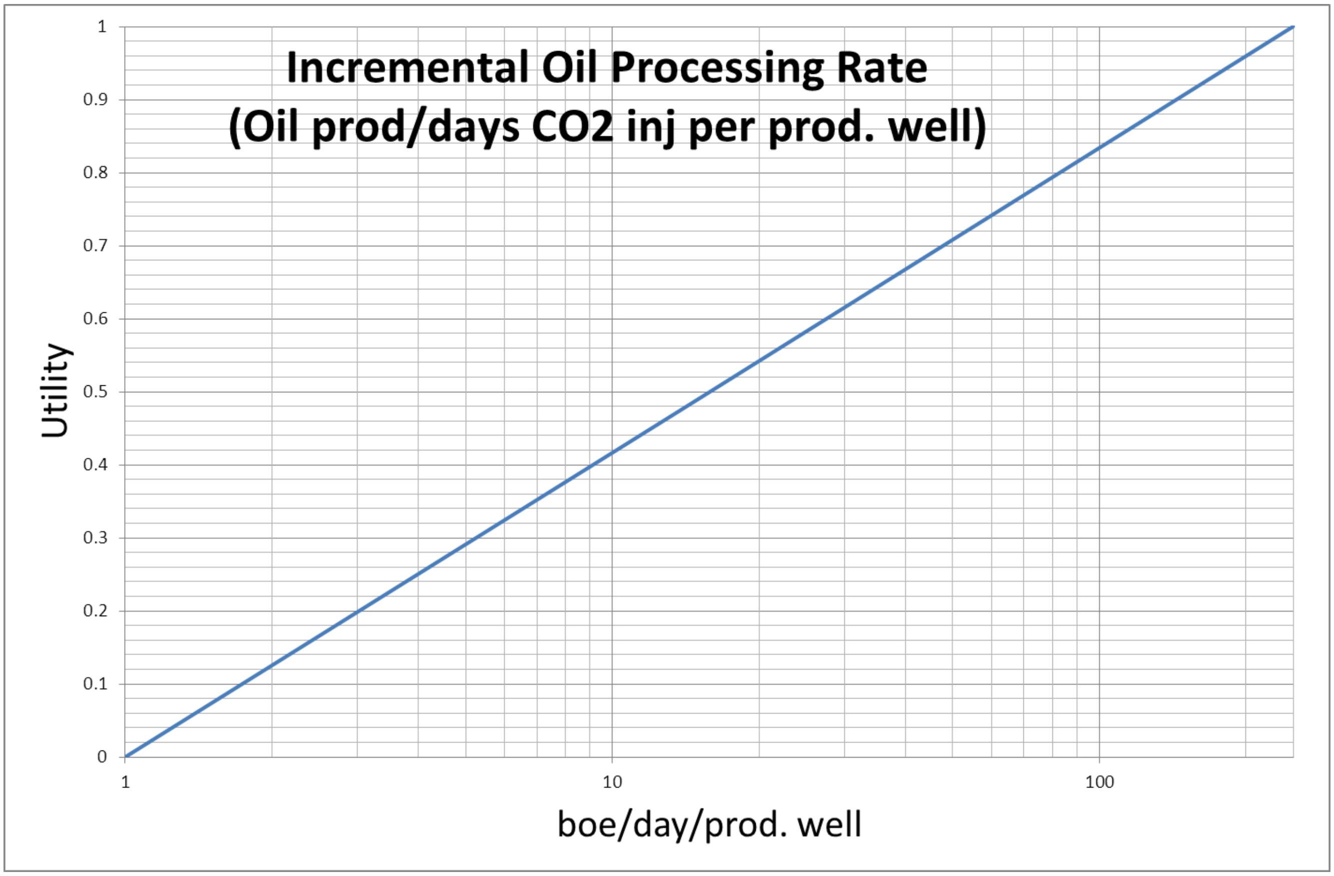
Pilot properties: CO_2 Gross and Net Utilization factors

The Gross utilization factor is the amount of CO_2 injected per bbl of oil produced based on cumulative data. The Net utilization factor is the difference between the cumulative amount of CO_2 injected and the cumulative amount of CO_2 produced divided by cumulative oil produced. Minimization of the amount of CO_2 injected is the goal to reduce CO_2 purchase or recycle costs. Since the produced CO_2 is almost always recycled in a commercial project, the CO_2 net utilization is equivalent to the amount of (new) CO_2 purchased. It was decided that for the pilots, the CO_2 net utilization was the least important of the two because the pilots were only run to 10 to 20% of an HCPV which would be relative early in the life of a commercial project, and in some cases not even to the point where CO_2 breakthrough occurred. If CO_2 breakthrough has not occurred, then Net Utilization = Gross unitization. For the pilots, the utilization factors had to be below 3 tonnes of CO_2/barrel of oil for the pilot to be considered.



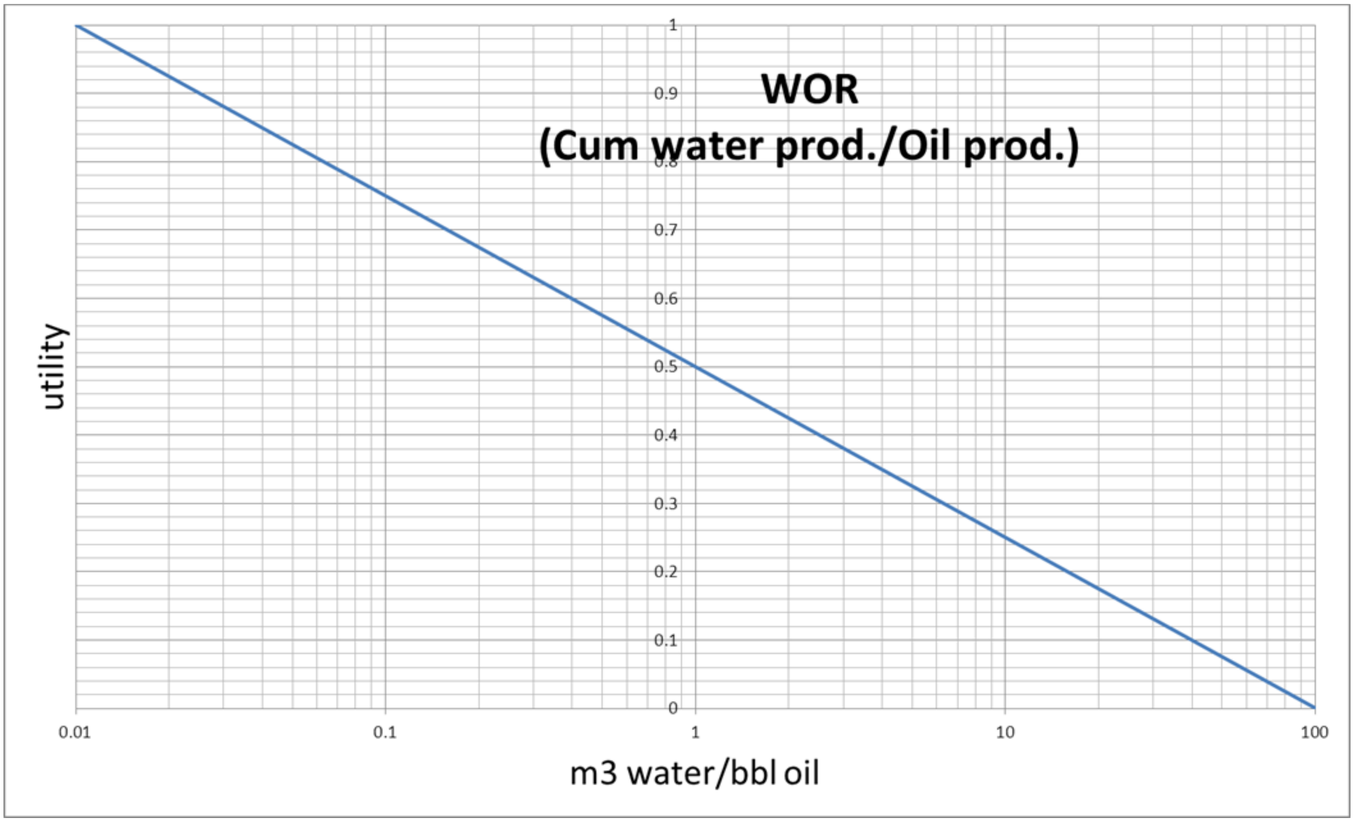
Pilot properties: Incremental Oil Processing Rate

Processing rate is very important for an oil company to have a profitable commercial project. A measure of this is the total oil and sales gas produced divided by the time period that CO_2 was injected for. To make it independent of the area of the oil pool being produced or the number of production wells, it is calculated on a per well basis A logarithm relationship is used,



Pilot Properties: WOR

Often CO_2 – EOR is a tertiary project, a follow up to a water flood. Consequently, during the CO_2 flood, large volumes of water are produced whose handling seriously affects the economics of the project. This is a logarithmic relationship.



APPENDIX 2

Future Scoring Improvements: Cumulative Oil Production as the Measure

The scoring scheme developed in this report assumes that all the scoring parameters are independent of each other. This is a high level evaluation similar to those that have been completed in the past. Its value lies in producing dimensionless curves which may be adjusted as more information becomes available on individual property variation and its effect on CO_2-EOR production. It is also very flexible, making different scenarios by changing the dimensionless utility curves and weights easy to test. A more robust analysis was suggested by Rivas et al, 1992. He used cumulative oil production as a measure of the attractiveness of the CO_2-EOR reservoir. He investigated the effect of varying one property at a time while keeping all others constant (i.e. single effect on cumulative oil production using a reservoir simulator to evaluate the optimum value for that property). A somewhat similar approach was followed by Valdez et al., 2011. This methodology suffers from a serious drawback, as it does not take account of the full interdependency of all parameters on cumulative oil production.

AITF (John Faltinson and Ali Jafari) have suggested the following approach. Ideally, if one varied all the reservoir properties simultaneously to see all the effects (single and combined) on cumulative oil production, then the range of cumulative oil production could be identified for a given value of a specific parameter (see Figure A2.1) and the actual cumulative oil production could be evaluated for discrete values of the properties of the reservoir in a straight forward manner using an excel spreadsheet. This is the ultimate application of ranking and scoring. To achieve this, a wide range of values for each reservoir property should be defined. Of course this is not possible as the number of combinations of reservoir properties is a huge number and the simulation run time would be unacceptably long (for instance, by defining 5 different values for 6 different reservoir parameters, the total number of simulation runs will be $5^6 = 15{,}625$).

One solution is to simplify the analysis by choosing an important subset of the reservoir parameters (rather than all) and choosing a limited number of values for each one which spans the natural variance of the corresponding parameter. It was decided that the first stage of this analysis should be limited to 6 properties and 3 values for each property ($3^6 = 729$). For each of the six properties, the three property values are chosen such that two of them represent extreme values at each end (on both positive and negative sides) with the third one lying somewhere in the middle of the range of pertinent property values to capture the shape of the resulting curves (see Figure A2.1) . In addition, a sensitivity analysis was conducted to determine the effect and importance of each reservoir property on the objective function (cumulative oil produced). These data could be used to calculate different parameter weights which are necessary in the aggregation process of scoring and ranking different reservoirs. The suggested properties to be evaluated in the sensitivity analysis are pressure, temperature, oil saturation, thickness, porosity and permeability. In a later stage, this could be tied into a spreadsheet economic model which evaluates revenue, infrastructure and operating cost, CO_2 storage opportunity, competitive technologies and CO_2 supply such as the Integrated Economic Model (Faltinson et al., 2008).

An example of the results for one property, permeability, would appear as illustrated in Figure A2.1 showing the three values of permeability modeled and the resulting area spanning the range of cumulative oil production for that property based on its interaction with the other 5 properties (each with 3 different values). At this first stage it could be used to rate CO_2-EOR reservoirs based on cumulative oil production. To incorporate the effect of different reservoir fluids in stage 2, the process is repeated using three different reservoir fluid compositions representing very light, medium and heavy oil with the result to be shown graphically to better understand and capture the influence of different reservoir fluid (composition) on the cumulative oil production. The resulting model will significantly improve the methodology for rating and scoring CO_2-EOR candidate oil reservoirs. It is believed that this is the future of screening and scoring oil reservoirs as candidates for CO_2-EOR.

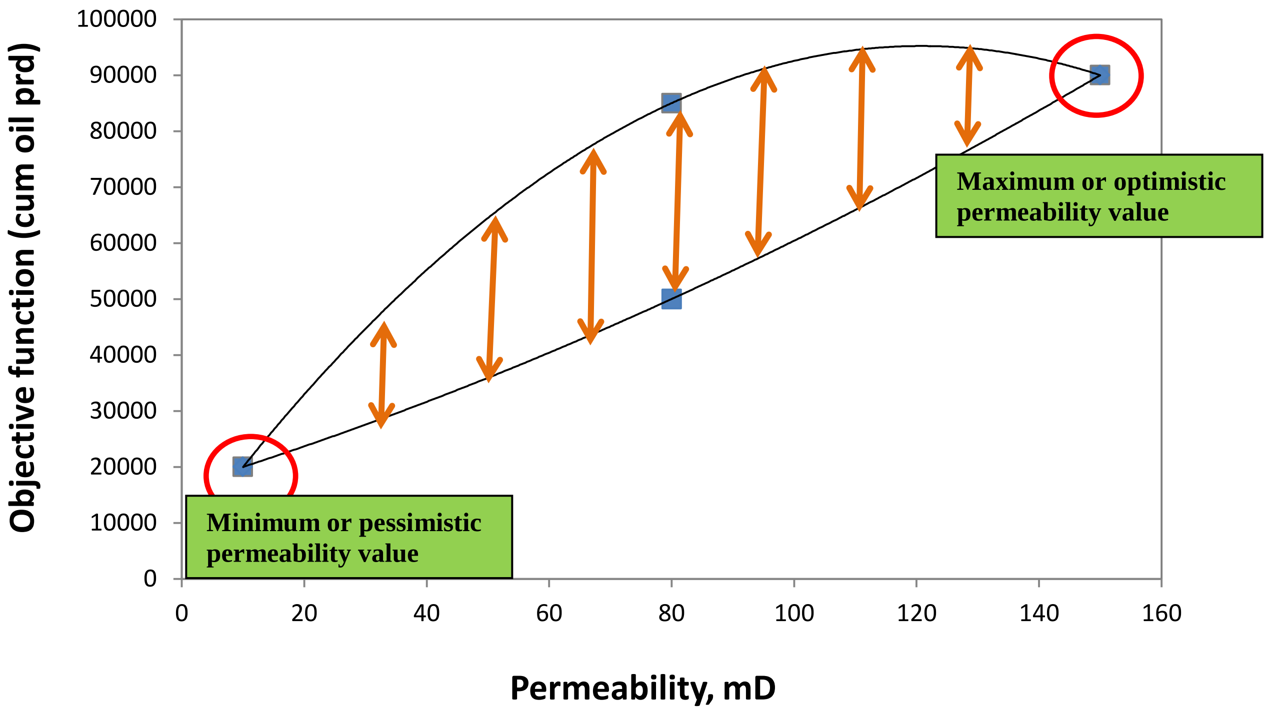


Figure A2.1: A sample plot model of permeability vs. cumulative oil production covering all possibilities given simultaneously varying 6 reservoir properties, each with 3 discrete values.