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The Business Case for a "Backbone" CO_2 Pipeline in Alberta

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Executive summary

There is considerable interest in having a "backbone" pipeline for carbon-dioxide (CO_2) built in Alberta—interest both on the part of major CO_2 emitters in the Athabasca oil-sands region and of oil producers, who could increase their production by injecting CO_2 into certain reservoirs if a ready, low-cost supply of CO_2 were available. Although no final plan has been put forward, the proposed pipeline would presumably run from Fort McMurray south and southwest to oil reservoirs amenable to CO_2 "enhanced oil recovery" (EOR) techniques in the central part of the province. [1]

This report examines the business case for constructing a backbone CO_2 pipeline in Alberta. It also addresses the likely growth in demand for CO_2 for EOR injection and current and future CO_2 supply sources in the province and their associated costs. The analysis suggests that construction of the CO_2 backbone for the sole purpose of delivering liquid CO_2 to oil reservoir sites for injection does not make sense from a business perspective because the supply of highly pure, low-cost, CO_2 from bitumen upgraders in the Edmonton/Fort McMurray area is likely to exceed CO_2 demand.

Current demand in Alberta for CO_2 for EOR purposes is very small (only one small commercial operation) and meaningful projections of the demand for CO_2 for enhanced recovery are simply not available. Further, there is considerable uncertainty as to how quickly and to what extent the demand for CO_2 to boost oil production will grow. On the other hand, a relatively large supply of low-cost CO_2 is expected to become available at existing and new bitumen upgraders in the Edmonton/Fort Saskatchewan area and this supply will probably be sufficient to meet the short to mid-term needs of the EOR operators. Since the price of CO_2 is determined by market forces, the excess supply resulting from construction of a backbone pipeline from Fort McMurray would likely cause the price of CO_2 to plunge. The big winners from construction of the backbone would therefore be the oil producers using carbon dioxide for EOR purposes.

As long as sufficient CO_2 is available from emitters in the Edmonton/Fort Saskatchewan area to meet petroleum industry's EOR requirements, a CO_2 backbone pipeline from Fort McMurray to the vicinity of the Pembina and Swan Hills/Judy Creek reservoirs cannot be justified on the basis of the economics. [2] What we are more likely

[1] EOR refers to methods of increasing oil production as with the injection of fluids other than water into a reservoir where testing indicates that the process increases the flow and therefore the recovery of oil from the reservoir.

[2] There could be an argument in favour of building the backbone if there were a strong likelihood that the demand for CO_2 for EOR purposes could grow more rapidly than expected; or if delays were expected in the construction of some of the upgraders indicated for the Fort Saskatchewan area so that a shortage of CO_2 would require some Alberta EOR operators to postpone their CO_2 injection plans. At time of writing, both appeared unlikely.

to see is the construction of smaller CO_2 pipelines running from supply sources near Edmonton/Fort Saskatchewan to the Redwater and Pembina reservoirs with a possible extension to Swan Hills/Judy Creek. If Alberta's CO_2 EOR requirements grow beyond the CO_2 supply capacity of upgraders and other facilities located in the Edmonton/Fort Saskatchewan area, construction of a pipeline from the Fort McMurray area could make sense depending on the volumes involved and the price of CO_2. This, however, does not appear to be in the cards in the foreseeable future.

There have been indications that a backbone CO_2 pipeline could cost upwards of 1.5 billion dollars and suggestions that the federal and Alberta governments each should contribute $0.5 billion towards the cost, while industry would bear the balance. If the main objective of the pipeline is to ensure that Alberta's oil producers with EOR projects can be assured of a sufficient and steady supply of CO_2, public support for a backbone project does not appear to be justified.

Introduction

There is considerable interest in having a "backbone" pipeline for carbon-dioxide (CO_2) built in Alberta—interest both on the part of major CO_2 emitters in the Athabasca oil-sands region and of oil producers, who could increase their production by injecting CO_2 into certain reservoirs. Essentially, the pipeline would run from Fort McMurray south and southwest to oil reservoirs amenable to CO_2 "enhanced oil recovery" (EOR) techniques in the central part of the province [Kaufman, 2006]. Environmentalists generally support the concept of such a pipeline because it could also transport CO_2 to depleted petroleum reservoirs for storage, thereby decreasing the amount of CO_2 released into the atmosphere. For their part, the emitters see a backbone pipeline as providing a market and therefore a revenue source for a portion of the CO_2 that they could have available as a consequence of the greenhouse-gas emission-intensity targets for large industrial emitters that Alberta has promised to legislate [Government of Alberta, 2007]. Companies involved in EOR projects would generally favour the proposed CO_2 transportation network because it would ensure the availability of a large pool of low-cost CO_2 to meet their injection requirements [Dielwart, 2006].

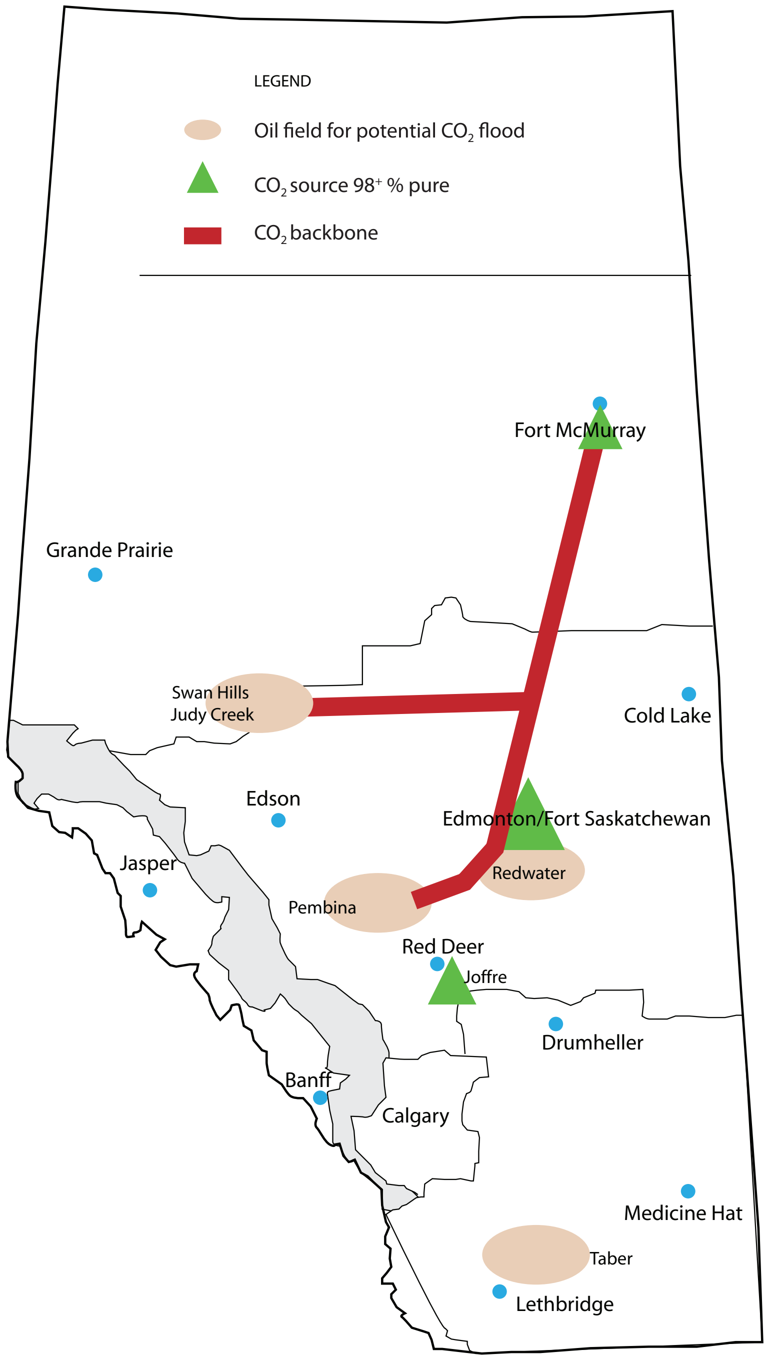
A joint announcement early in March 2007 by the provincial and federal governments indicated that they are interested in identifying the challenges associated with a "large-scale carbon dioxide capture and storage system to capture and transport CO_2 for use in enhanced oil recovery or for underground capture and storage" [Canada, Office of the Prime Minister, 2007]. This report examines the business case for constructing a backbone CO_2 pipeline from the vicinity of Fort McMurray to the Pembina and Swan Hills/Judy Creek oil fields: our analysis suggests that construction of the CO_2 backbone does not make sense from a business perspective because, for the foreseeable future, sufficient CO_2 will likely be available in the Edmonton/Fort Saskatchewan area alone to meet the needs of those operating EOR projects in Alberta. While discussion of plans for a CO_2 pipeline from Fort McMurray is topical because of public interest in environmental issues, use of taxpayers' dollars to support the project is questionable.

Background

A CO_2 backbone

The proposed backbone CO_2 pipeline would most likely run from Fort McMurray south to the Pembina oil field southwest of Edmonton, with a branch to the Swan Hills oil field northwest of Edmonton or, alternatively, southwest to Swan Hills and then southeast to the Pembina field. The pipeline would be filled with CO_2 both at Fort McMurray and in the vicinity of Edmonton/Fort Saskatchewan [figure 1]. As the market grows, CO_2 could also be picked up at and delivered to additional points.

Figure 1: Proposed route for backbone CO_2 pipeline



Enhanced oil recovery

Enhanced oil recovery (EOR) is the production of oil with the aid of "enhanced" technology methods following the primary production phase and generally also following a water-driven or secondary production phase. EOR is sometimes referred to as "tertiary" production since it follows the primary and waterflood production stages.

EOR techniques can involve miscible or non-miscible flooding using hydrocarbon fluids such as ethane or liquefied CO_2. In the case of CO_2 flooding, the section of the reservoir accessed by the injection well is first swept by water flooding, followed by CO_2 injection and then by more water. While the CO_2 that is injected is collected and recycled, a small portion is generally retained in the reservoir, at least for some time, depending on the physical characteristics of the reservoir. Because the amount of the injected CO_2 that is retained in the reservoir tends to decline gradually, the quantity of "new" CO_2 that must be added to the CO_2 that is being recycled in each new injection round generally diminishes with time.

CO_2 capture and storage

CO_2 capture and storage is the containment of CO_2 at the point of emission and consequential sequestration or storage of the gas on site, in a pipeline system, a depleted aquifer, salt cavern, or depleted petroleum reservoir. Some storage may be achievable in a petroleum reservoir where an EOR production program using CO_2 injection is underway if it can be expected that a significant portion of the injected volumes will remain in the reservoir. In order to transport CO_2 efficiently by pipeline, it is generally transformed to a liquid state via compression.

Alberta's experience using CO_2 for enhanced oil recovery operations

The potential benefits of EOR using CO_2 injection have been known for many years. However, the adoption of this technique in Alberta was constrained by low oil prices, the availability of relatively cheap hydrocarbons (such as ethane) for EOR injection, and the absence of readily available low-cost supplies of CO_2. To date, CO_2 flooding on a commercial basis in Alberta has been limited to an operation near NOVA Chemicals' Joffre polyethylene plant. The CO_2 EOR operation there was initiated as a pilot project by the Alberta Oil Sands Technology and Research Authority (AOSTRA) in 1984. The

CO_2 for the project comes from a NOVA Chemicals ethylene-gas plant located a few kilometers from the oil field where the CO_2 is extracted from the ethane feedstock [Luhning, Glanzer, Noble, and Wang, 2005].

In order to provide an incentive for CO_2-injection pilot projects, the Alberta Government initiated a $15-million royalty credit program in 2004, in which four projects were selected in various parts of the province. These included a project by Devon Canada at Swan Hills (now discontinued) and another by Penn West Energy Trust (Penn West) in the Pembina field southwest of Edmonton. The two other pilot or experimental (i.e. not commercially justifiable) projects are at Zama Keg River in northwest Alberta and at Enchant Arcs in the south. [1]

One of the most active Canadian EOR operators with CO_2 injection experience is Penn West, the operator of the CO_2 EOR project at Joffre. Penn West is planning to initiate commercial development in the Pembina Cardium Pool, Canada's largest light oil pool, during the 2009-2010 period if an adequate, low-cost supply of CO_2 can be secured. The company estimates that the net incremental oil production from CO_2 injection at the Pembina field (where it has been operating a CO_2 pilot since 2005) could range from 150 million to 400 million barrels of oil [Penn West Energy Trust, 2007]. According to information about the CO_2 Injection Flood project in Weyburn, Saskatchewan, it is assumed that up to 4.5 mcf of CO_2 would be required per barrel of oil produced [Hassan, 2006]. Therefore, a considerable quantity of CO_2 would be required over the life of the project. [2]

Penn West has indicated that it is exploring potential CO_2 supply arrangements with two large future bitumen upgraders [3] in the Edmonton/Fort Saskatchewan area capable of supplying a reliable source of CO_2 with a high level of purity [Penn West Energy Trust, 2007]. If an agreement can be reached, a pipeline running from the proposed upgraders to Penn West's Pembina field locations may be built. Penn West is also planning to initiate a CO_2 injection pilot in the South Swan Hills Beaver Lake Pool. If it were decided to commence commercial-scale operations in the Swan Hills area, construction of a CO_2 pipeline to the Pembina reservoir could be followed very quickly thereafter by a northward extension.

[1] NOVA Chemicals, with a ready supply of CO_2 at its Joffre polyethylene plant, has been involved in one of these pilots. According to NOVA, the firm "structures CO_2 capture arrangements to cover costs and seeks opportunities to share in producer benefits." In order to minimize transportation costs, NOVA accessed an existing liquids pipeline to deliver CO_2 to one project [Flint, 2006].

[2] 4.5 mcf of CO_2 per barrel of oil is the utilization rate at the CO_2 flood in Weyburn, Saskatchewan. The utilization rate is the ratio of the net CO_2 that is used to the incremental oil production attributable to CO_2 injection. Net CO_2 is the total amount of CO_2 injected less the recycled amount.

[3] Upgraders are facilities that process very heavy oil or bitumen, converting it to lighter, sweeter (i.e. low sulphur) crude oils that are refinery ready. The upgrading process requires a steady stream of hydrogen. The on-site hydrogen plants are a source of high quality CO_2.

Cost of capturing and transporting CO_2

Two key elements of commercial CO_2 transportation arrangements are a receipt point (pipeline interface) price for the CO_2 that is agreeable to the seller and a delivery point price (receipt point price plus transportation cost) that is agreeable to the buyer. Estimates of the cost of capturing CO_2 vary widely [table 1], depending on the source [Fisher, Sloan and Mortensen, 2003; Godec, 2006]. For example, analysis by the Canadian Energy Research Institute (CERI) indicates that the cost of capture varies from $25/tonne ($1.28/mcf) to $191/tonne ($9.79/mcf) [Fisher, Sloan and Mortensen, 2003], [4] with the lowest cost associated with a "high-purity source." [5] By way of comparison, the upper-end cost of capture at an integrated gasification combined cycle (IGCC) power plant is about $45/tonne or $2.30/mcf. The cost of CO_2 capture using a hydrogen recovery unit that involves a process known as "pressure-swing adsorption" is indicated to be $95/tonne or $4.87/mcf. Capture costs at conventional coal-fired power plants are reportedly 2.5 times greater than those at an IGCC facility. In the case of cogeneration plants, the costs are greater than with any of the other sources documented because larger capture facilities are needed to capture CO_2 from the relatively dilute flue gas streams [Fisher, Sloan, and Mortensen, 2003]. [6]

According to researchers at Enbridge Pipelines Inc., the cost to collect, dehydrate and compress CO_2 before it enters a pipeline adds an additional $3.50/tonne ($0.18/mcf) to the cost [Luhning, Glanzer, Noble, and Wang, 2005]. This estimate is low in comparison with Advanced Resources International's estimate of $0.35/mcf to $0.70/mcf for compression alone [Godec, 2006]. Adding this pipeline-preparation cost to the cost of capture indicates that the total pipeline receipt-point cost could be as low as $0.70/mcf (the Advanced Resources International estimate) in the case of CO_2 from a highly pure source, where there is no capture cost as such. However, the CERI's analysis suggests that the average cost of CO_2 entering a hypothetical Alberta pipeline system today would likely be as high as $4.50/mcf or greater [Fisher, Sloan, and Mortensen, 2003]. This is because substantial volumes would have to come from cogeneration facilities, natural gas processing plants, cement plants, and other facilities, where the cost of capture is considerably greater than at upgraders with state-of-the-art hydrogen plants.

[4] US dollar information converted to Canadian dollars assuming CDN$1.00 is worth US$0.84.

[5] The lowest costs are in relation to pure CO_2 streams, such as those from hydrogen, ethylene, and natural gas processing plants where there are no "capture" costs as such, only compression costs, which are estimated to be in the range of $0.35 to $0.70 cents per mcf [Advanced Resources International, 2006].

[6] These estimates assume that any incremental CO2 emitted because of the capture process itself is also captured with the result that the estimated cost reflects the cost of abatement.

Table 1: Estimates of the delivered cost of CO_2 at EOR wellhead

Source of CO_2	EOR Site	Cost (CDN$/mcf)	Source and date of cost estimate
Mainly piped from natural sources	Permian Basin	0.60–1.79	Townsend, Bill, Blue Source LLC, 2006
Coal electric-generation unit in North Dakota	Weyburn, Saskatchewan	1.28	Hassan, Dave, EnCana Corporation, 2006
Alberta gathering system if built today	Central Alberta	5.00	Fisher, Sloan and Mortensen, 2003
Highly pure CO_2 streams from low-cost (e.g.new upgrader H unit or IGCC) power plant) source	Central Alberta	3.00–3.50	Godec, Michael, Advanced Resources Intl., 2006

The average cost of capturing CO_2 in Alberta will gradually come down as technologies improve and capture facilities are installed at new bitumen upgraders with highly pure streams of CO_2 from hydrogen units. The eventual deployment of coal-fired power plants using IGCC technology will provide additional low-cost sources. If all of the CO_2 supplying an integrated pipeline system were to come only from low-cost sources (e.g., state-of-the-art upgraders and IGCC plants), it should be possible to maintain the average receipt-point cost below $3.00/mcf based on cost information provided by Advanced Resources International [Godec, 2006]. [7]

According to CERI, the pipeline toll for a 24-inch pipeline running from Fort McMurray oil-sands operations to petroleum reservoirs in central Alberta would likely be about $8/tonne or $0.41/mcf [Fisher, Sloan, and Mortensen, 2003]. This suggests that the average delivery-point cost of CO_2 to EOR buyers *today* would probably be around $5.00/mcf. This compares with prices in the range of US$0.50/mcf to US$1.50/mcf that oil producers in the Permian Basin in Texas (where most of the CO_2 consumed is being piped from natural sources) are paying for CO_2 [Townsend, 2006]. [8] The all-in delivery-point price that EnCana pays for the CO_2 that is being piped to the Weyburn, Saskatchewan, field from the Dakota Gasification coal-fired power plant in North Dakota is reportedly only about $25/tonne or about $1.28/mcf, including the transportation cost [Hassan, 2006]. [9]

[7] As CO_2 capture becomes mandated in more jurisdictions, technological improvements can be expected to lead to cost reductions. However, the extent and timing of such reductions is unknown.

[8] The CO_2 contract price is frequently a function of the price of oil.

[9] In order to obtain detailed, up-to-date information about the feasibility of CO_2 capture in the Edmonton/Fort Saskatchewan area for potential EOR applications in the Swan Hills and Pembina Cardium fields, the Petroleum Technology Alliance of Canada (PTAC) is initiating a

At what cost is CO_2 too expensive for EOR?

Table 2 illustrates the sensitivity of oil producers' net-backs to the price of CO_2. Because of the volatility of oil prices (and the associated risk), it is assumed that the price of oil used for planning purposes is US$50/bbl. The analysis summarized in the table suggests that EOR operators would probably not enter into *take or pay* contracts for CO_2 if they were planning on injecting the substance at the rate of 4.5 mcf per barrel of oil recovered (the rate at which EnCana is reportedly injecting at Weyburn, Saskatchewan) and if the delivered cost of CO_2 were as high as, or greater than, $4.50 per mcf. [10] In fact, given the risks involved and the need to earn a satisfactory after-tax return on investment, they could require a somewhat lower all-in CO_2 price to feel comfortable about entering into a long-term supply arrangement. Essentially, this is because of the production risk (i.e. the fact that there is no assurance that injecting the assumed amount of CO_2 per expected barrel of oil production would continue to yield a barrel of oil) and the price risk.

With oil companies not interested in purchasing CO_2 for, say, a delivered price of $4.00/mcf or higher, and transportation costs likely in the vicinity of $0.50/mcf, large CO_2 emitters with capture and compression costs in the vicinity of $3.50/mcf or higher will not be motivated to install the necessary capture equipment unless mandated to do so. This suggests that only CO_2 suppliers with low-cost, high-quality sources, as from state-of-the-art hydrogen units at new upgraders, would be able to profit from the sale of CO_2. [11]

Potential demand for CO_2 by EOR operations

How much CO2 Alberta's EOR producers would take, if it were available at what they regard as affordable prices, has been the subject of numerous estimates. One indication is that three major, light-oil pools in Alberta (Swan Hills, Pembina and Taber), where production rates could be improved through CO_2 injection, together could require as

study. The request for proposal indicates that the PTAC CO_2 Enhanced Hydrocarbon Recovery (EHR) Steering Committee "believes that sufficient CO_2 exists in the Fort Saskatchewan area to support … commercial scale enhanced recovery of conventional oil in the Pembina and Swan Hills fields" [Petroleum Technology Alliance Canada, 2006: 1]. The objective of the study is to quantify the capital and operating costs involved to aggregate CO_2 for EHR in the area.

[10] *Take or pay* contracts assure the supplier that the CO_2 buyer will pay for all of the CO_2 volume contracted for, whether or not the volume that is taken is that large.

[11] Emitters forced to install CO_2 capture equipment who have higher costs may well wish to market CO_2 at a loss in order to offset a portion of the costs.

Table 2: CO_2 EOR producer netback analysis, with injection rate of 4.5 mcf/bbl

	1	2	3	4
West Texas Intermediate oil price (US$/bbl)	50.00	50.00	50.00	50.00
Exchange rate	0.85	0.85	0.85	0.85
Oil price (CDN$/bbl)	58.82	58.82	58.82	58.82
Royalty (10% of CDN price)	5.88	5.88	5.88	5.88
CO_2 cost/bbl [1]	6.75	14.63	20.25	25.88
Operating expenses (40% of CDN price/bbl)	23.53	23.53	23.53	23.53
Total Costs and Royalties	36.16	44.04	49.66	55.29
Operating netback (CDN$/bbl)	**22.66**	**14.79**	**9.16**	**3.54**
Estimated delivered cost of CO_2 (CDN$/mcf)	1.50	3.25	4.50	5.75

Note 1: The assumed injection rate of 4.5 mcf/bbl × the estimated delivered cost of CO_2 per mcf.

much as 10,500 tonnes of CO_2 per day [Luhning, Glanzer, Noble, and Wang, 2005]. By way of comparison, the very successful CO_2 EOR operation at Weyburn, Saskatchewan, is now using 7,500 tonnes of CO_2 per day, which is shared with the adjacent Midale operation [Hassan, 2006]. In a presentation to the Petroleum Technology Alliance Canada (PTAC) CO_2 Forum in November 2006, John Dielwart, CEO of ARC Resources, indicated that "under the right conditions, ARC alone could be injecting 20,000 tonnes of CO_2 per day" [Dielwart, 2006: slide 18]. He explained that most of this supply would be required in relation to ARC Resources' interest in the Redwater reservoir (near Strathcona) and Pembina Alberta fields. [12] Although the extent to which the Redwater reservoir may be amenable to CO_2 flooding is yet to be determined, that field's proximity to future upgraders in the Edmonton/Fort Saskatchewan vicinity is an important reason that ARC Resources is assessing the potential for CO_2 EOR there with a great deal of interest.

ARC Resources' projections of CO_2 requirements relate only to their own use. Moreover, their projection of the demand for CO_2 injection for EOR purposes does not reflect the use of CO_2 to boost production in coal-bed methane applications. Therefore, it is possible that the peak rate of total CO_2 consumption in Alberta for enhanced petroleum production (i.e. both oil and gas) could grow to 50,000 tonnes of CO_2 per day or more during the next ten years, if supplies of CO_2 were readily available on a cost-effective basis.

[12] Only a small portion would be used as a result of the company's working-interest ownership in the Weyburn and Midale fields in Saskatchewan, which are supplied with CO_2 via pipeline from North Dakota.

The current demand for CO_2 for EOR is very small (only the one small commercial operation at Joffre) and meaningful projections of the demand for CO_2 for enhanced recovery are not available. Further, there is considerable uncertainty as to how quickly, and to what extent, the demand for CO_2 to boost oil production will grow. For these reasons, the business case for building a backbone CO_2 pipeline to serve the needs of the petroleum industry anytime soon is weak. [13]

Potential supplies of CO_2

From 5,000 to 7,000 tonnes of CO_2 per day could be captured from a hydrogen plant at a typical 100,000 barrels per day (bpd) upgrader facility [Kaufman, 2006]. [14] Considering the number of bitumen upgraders either already in place, under construction, or planned for Alberta, it appears that the supply of high-quality CO_2 will be abundant in relation to the anticipated demand for EOR CO_2.

Table 3 summarizes the outlook for the construction of new upgraders in the Edmonton/Fort Saskatchewan area. The table indicates that by 2015 more than 1,500,000 barrels per day of new upgrading capacity could be built in that region. At 5,000 tonnes of CO_2 per 100,000 barrels of capacity, the indicated new projects and expansions could be the source of as much as 75,000 tonnes of CO_2 per day. Given the existing sources of CO_2 that are available there and the outlook for CO_2 requirements for EOR, this suggests that a CO_2 backbone from Fort McMurray will not be necessary to meet the CO_2 needs of Alberta's EOR operators.

If a backbone pipeline were built from Fort McMurray to the Pembina oil field and linked to a gathering system connecting CO_2 sources in the Edmonton/Fort Saskatchewan vicinity, much more low-cost CO_2 would be available to meet the CO_2 requirements of Alberta's EOR producers than required. Future additions to the coal-fired generation fleet that employ break-through, Integrated Gasification Combined Cycle (IGCC) technologies would provide still more sources of high-grade, low-cost CO_2, as would additional upgraders that have yet to be approved and identified. [15]

[13] If the backbone were built and CO_2 became available at the major reservoirs where CO_2 EOR activity could thrive, this could spur demand growth but the extent to which this might happen is subject to speculation.

[14] About the same amount can be sourced from an 850 MW Combined Cycle Gas Turbine (CCGT), gas-fired, electric-generation unit using today's technology [Le Thiez, 2006].

[15] Essentially, IGCC technology involves gasification of coal. The process provides for ready sequestration of CO_2 before the heated gases are used to drive the electric-generation turbines.

Table 3: Upgraders planned for the Edmonton/Fort Saskatchewan area

Company	Project	Capacity (barrels/day)	Period
BA Energy	Heartland	250,000	2006–2012
Northwest Energy	Upgrader	150,000	2008–2014
North American Oil Sands	Upgrader	160,000	2011–2015
Petro-Canada	Fort Hills	320,000	2009–2015
Shell Canada	Scotford	500,000	2007–2015
Synenco Energy	Northern Lights	100,000	2008–2012
Total E&P Canada	Upgrader	200,000	2008–2014
Total		1,680,000	

Sources: Clelland, 2007; Lynch, 2007; Wall, 2007; Total E&P Canada, 2007.

The consequences of an excess supply of CO_2

If the price of CO_2 were determined by market forces, the excess supply resulting from construction of a pipeline from Fort McMurray to the Pembina and Swan Hills/Judy Creek fields would cause the price of CO_2 to plunge. Upgraders and other suppliers in the Edmonton/Fort Saskatchewan area who were engaged in selling CO_2 to EOR operators would soon discover that suppliers in the Fort McMurray region were offering the substance at lower prices. Eventually, large emitters in the vicinity of Fort McMurray could then be expected to attempt to persuade the Alberta government to establish a floor price that would enable them to continue to enjoy a significant return on their investment in CO_2 capture equipment and, in effect, ensure that the EOR operators pay a "fair" price for the CO_2. Ironically, the companies engaged in EOR activities, which have also been actively promoting public support for the backbone, could be expected to urge the provincial government to resist any kind of market intervention. If the government heeded their advice, they would be the main beneficiaries, enjoying much lower prices for CO_2 than otherwise. Ancillary benefits would include increased employment of oilfield workers because of greater EOR activity. [16]

[16] Given that there will be a shortage of workers in Alberta to construct, operate, and maintain the oil-sands projects, the additional demand would place further pressure on wages and other costs.

Environmental considerations

The construction of any pipeline has environmental implications. For this reason, every pipeline project must pass the scrutiny of an environmental impact assessment and the authorities must be satisfied that the environmental requirements will be met. The mandating of CO_2 capture by large emitters is now virtually a certainty given the provincial government's promised emissions legislation [Alberta Environment, 2007]. Bill 3, the *Climate Change and Emissions Management Amendment Act*, will require major emitters to reduce greenhouse gases by 12%, commencing July 1, 2007. [17] Given that this or a similar approach had been anticipated for some time, it is not surprising that large emitters in the Fort McMurray area have been seeking government support for the backbone. Their principal objectives have been to ensure that the pipeline is built for as little cost as possible and to benefit from sales of CO_2 to EOR producers; and thereby to enjoy at least some return on the costs that they will incur in installing equipment to capture CO_2 [Kaufman, 2006].

The large emitters situated around Fort McMurray are also interested in the backbone pipeline because it would allow them to transport CO_2 to depleted petroleum reservoirs for storage. Whether or not an Alberta CO_2 backbone pipeline will be needed to deliver CO_2 to underground storage sites in south central Alberta is beyond the scope of this paper. If such a pipeline were necessary, then having the companies that are the source of the CO_2 pay for the transportation and related storage fees would ensure that such costs are recognized as part of their overall cost of doing business. Internalization of the CO2 disposal costs in this way would ensure that the prices of bitumen and upgraded product ultimately reflect those costs.

Conclusion

The main conclusion is that construction of an Alberta CO_2 backbone pipeline from Fort McMurray is unnecessary because the large supply of low-cost CO_2 potentially available from existing and future bitumen upgraders in the Edmonton/Fort Saskatchewan area will be more than sufficient to meet the needs of the EOR operators. Together, the existing Shell Scotford upgrader (once expanded as per the planned expansion of the Athabasca Oil Sands Project) and the future Heartland, Northern Lights (Synenco Energy), North American Oil Sands Northwest Energy, Fort Hills (Petro-Canada) and

[17] The only exceptions are that an emitter will probably be permitted to purchase an Alberta-based offset or to contribute to a new fund that will invest in technology to reduce emissions.

Total upgraders will be capable of supplying as much as 75,000 tonnes of low-cost CO_2 per day. If necessary, this could be augmented by supplies from the chemical plants (Agrium, Sherritt, and Dow) in the area. The total supply will probably be more than sufficient to meet the needs of EOR operators for many years to come.

As long as sufficient CO_2 is available in the Edmonton/Fort Saskatchewan area to meet the petroleum industry's needs, a CO_2 backbone pipeline from Fort McMurray to the Pembina and Swan Hills/Judy Creek oil fields cannot be justified on the basis of the economics. [18] What we are more likely to see is the construction of smaller CO_2 pipelines running from supply sources near Fort Saskatchewan to the Redwater and Pembina reservoirs along the lines of what Penn West has been proposing, with a possible extension to Swan Hills [Penn West Energy Trust, 2006]. If CO_2 EOR requirements in Alberta grow beyond the CO_2 supply capacity of upgraders and other facilities in the Edmonton/Fort Saskatchewan area, construction of a pipeline from the Fort McMurray area could make sense depending on the volumes involved and the price of CO_2. This, however, does not appear to be in the cards in the foreseeable future.

If the CO_2 backbone were built in response to the existing and potential market resulting from EOR projects, the major beneficiaries would be the EOR operators and, to a lesser extent, the large emitters. Because these players are fully capable of absorbing the cost of the pipeline themselves, public support for the project is unwarranted.

If there is "demand" for CO_2 beyond EOR, such as strong public interest in storing it in underground reservoirs to reduce atmospheric emissions—and this requires that a pipeline be built to transport CO_2 from the Fort McMurray area to locations in south central Alberta—there could be a role for government involvement. However, whether environmental policy objectives in relation to CO_2 emissions would be met most efficiently by subsidizing the cost of constructing a pipeline to storage reservoirs is a question that is beyond the scope of the present paper.

[18] Building the backbone would be plausible under two circumstances. First, if the demand for CO_2 for EOR purposes grew more rapidly than expected; second, if there were delays in the construction of some of the upgraders indicated for the Fort Saskatchewan area, causing a shortage of CO_2 supply that would require some Alberta EOR operators to postpone their CO_2 injection plans. At the time of publication, it appeared that the likelihood of this happening was quite low.

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