Carbon Capture and Sequestration, the technology that will allow Canada to develop the Alberta Oil Sands, *and* meet its Kyoto Targets?

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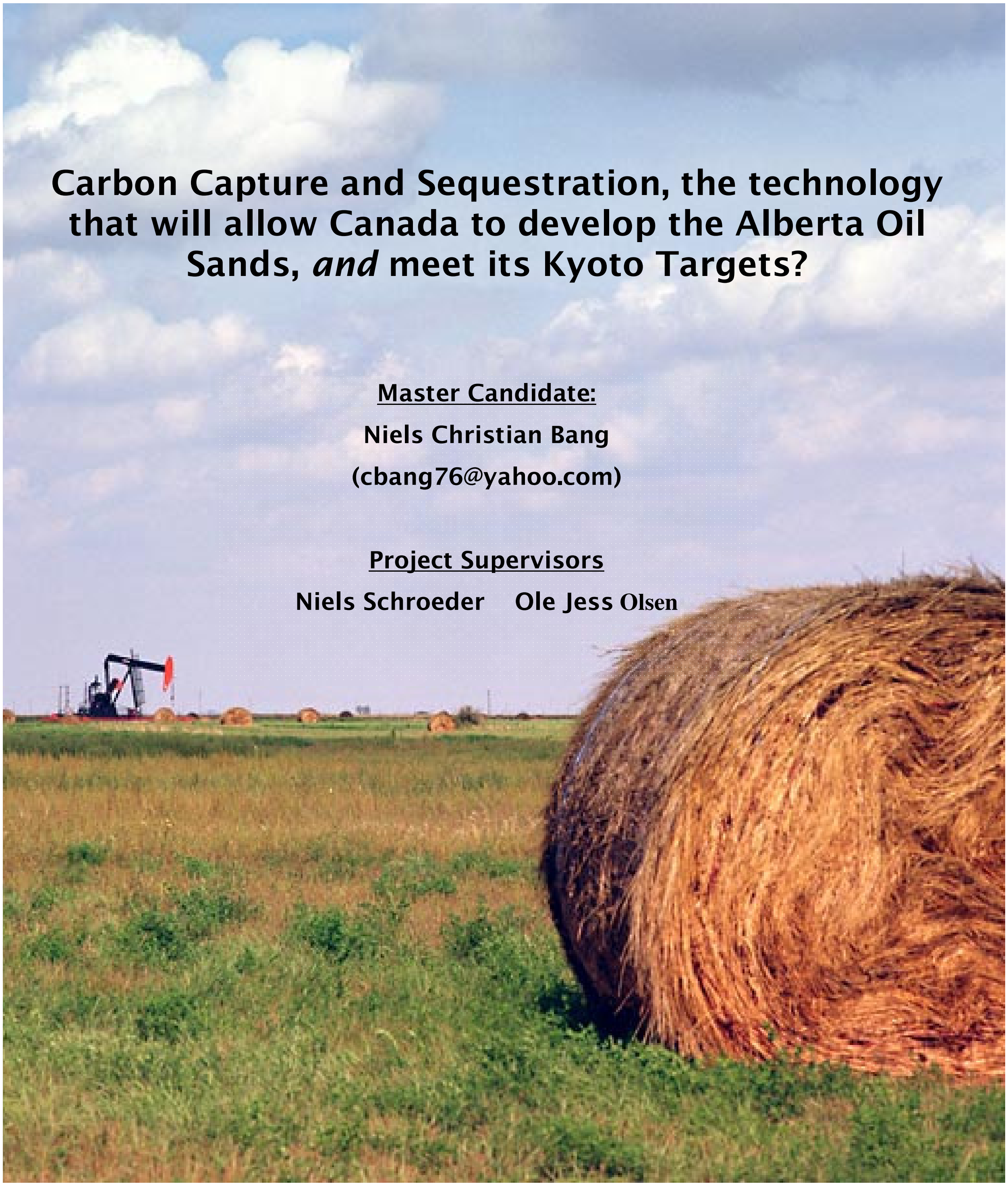

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Cover Photo: One of numerous EOR fields in Western Canada where CO_2 could be sequestered.

Courtesy: Petroleum Technology Research Centre and Canadian Geographic
http://www.canadiangeographic.ca/magazine/JF08/indepth/weyburn.asp#

Executive Summary

Human induced global climate change resulting from the increased release of greenhouse gas emissions represents one of the most pressing environmental concerns facing our generation. To help combat this, the United Nations Framework Convention on Climate was ratified by 189 members and it laid the groundwork for the Kyoto Protocol which called on countries to agree to voluntary emission reductions based on 1990 levels. Canada was among those countries that ratified the Kyoto Protocol and it agreed to a 6% reduction, a commitment which called on Canada to lower annual average emissions below 563Mt for the 2008-2012 period. However, since this time Canada's emissions have steadily increased with the most recently published numbers revealing 2005 annual emissions of 747M. While meeting its Kyoto commitments during the 2008-2012 period now seems highly unlikely, simply meeting these targets at all within the next decade will require Canada to make emission reductions of over 184Mt.

Within Canada, the largest single contributor to the recent growth in these emissions is the extensive oil sands operations taking part in the province of Alberta. Due to the poor quality of the oil significant amounts of energy and water are required to produce the final synthetic crude oil, and as a result large amounts of GHGs and other pollutants are released. Despite the environmental drawbacks, the economic and political pressure to develop a resource thought to have reserves over 173 billion barrels of oil has been enormous, and thus massive development has taken place.

Given these competing interests, the question therefore becomes: How can the Alberta oil sands be developed while at the same time allowing Canada to meet its Kyoto commitments? An important principle that was taken into consideration when answering this question was that of 'polluter pays', that is, if an industry pollutes in the pursuit of profit it should be responsible for this pollution, and therefore any solution should be based primarily on private sector investment. Via literature review and the interviewing of experts within the fields of Carbon Capture and Sequestration (CCS) and Enhanced Oil Recovery (EOR), it was determined that the establishment of a large-scale CCS network in Western Canada represents the most cost-effective option for reaching Canada's emission targets. While such a network would be costly to build, these costs could largely be borne by private sector companies involved in EOR, particularly if government legislation provided these EOR developers with a favourable royalty regime and a stable and comprehensive regulatory framework with respect to domestic GHG emissions.

Acknowledgements

Firstly I would like to thank my supervisors, Niels Schroeder and Ole Jess Olsen for their guidance and constructive criticism throughout the writing of my thesis, particularly given the fact that my work often came in sporadic bursts. As well I would like to thank Per Homann Jespersen both for filling in at the last moment, and also for the various articles he has sent me over the course of my studies. In addition I would like to thank Susanne Jensen for answering my slew of questions during my time at TEKSAM and Bente Kjærgård for her patience and understanding. A sincere thank you also goes to Daragh Glynn who agreed to act as my opponent group despite the fact that his wife was expecting and he had his own thesis to complete.

I am also very grateful to the fine gentlemen who agreed to be interviewed during the course of my research: Dr Stefan Bachu (Alberta Energy and Utilities Board), Eric Beynon (Integrated CO2 Network), Dr. Malcolm Wilson (University of Regina), and Shane Silverberg (Penn West Energy). All are very busy individuals and I greatly appreciated the fact that they not only answered my questions, but even took the time to edit the transcripts I sent them.

Lastly I would like to thank my friends, family and co-workers for their support and understanding, particularly my cousins Søren and Ole, whose knowledge of computers proved most helpful, and my sister and her fiancée who looked after me so well as I spent hours at their home writing and conducting interviews. Last but certainly not least, I would like to thank my parents for their constant encouragement and support during the years of my studies (and there have indeed been many of them), I may not have said it enough over those years, but Thank You.

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Acronyms, Abbreviations and Chemical Formulas

AECO	Alberta Gas Trading Price
AOSTRA	Alberta Oil Sands Technology and Research Authority
CAPP	Canadian Association of Petroleum Producers
CCS	Carbon Capture and Sequestration
CFCs	Chloro fluorocarbons
CH_4	Methane
C_2H_4	Ethane
C_3H_8	Propane
C_4H_{10}	Butane
CHP	Combined Heat and Power
CO	Carbon Monoxide
CO2	Carbon Dioxide
CO_2e	Carbon Dioxide equivalent
CSS	Cyclic Steam Stimulation
ECBM	Enhanced Coalbed methane
ENGR	Enhanced Natural Gas Recovery
EOR	Enhanced Oil Recovery
EU	European Union
GHG	Greenhouse Gas
Gt	Gigatonne (One Billion Tonnes)
H_2	Hydrogen
HFCs	Hydro fluorocarbons
ICO2N	Integrated CO2 Network
IEA	International Energy Organisation
IGCC	Integrated gasification combined cycle
IGHC	Integrated gasification hybrid cycle
MFT	Mature Fine Tailings
MIT	Massachusetts Institute of Technology
Mt	Million Tonnes
MW	Megawatt (One Million Watts)
NEB	National Energy Board
NO_x	Nitrogen Oxide
NTREE	National Roundtable on the Environment and the Economy
OECD	Organisation for Economic Co-operation and Development
OPEC	The Organization of the Petroleum Exporting Countries
PPP	Polluter Pays Principle
SAGD	Steam Assisted Gravity Drainage
SCO	Synthetic Crude Oil
SMR	Steam Methane Reforming
SCPC	Supercritical Pulverized Coal Unit
UNFCCC	United Nations Framework Convention on Climate Change
VAPEX	Vapour Extraction
WCSB	Western Canadian Sedimentary Basin
WTI	West Texas Intermediate

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Chapter 1 – Introduction

1.1 Introduction to problem field

Global climate change resulting from a human induced enhanced greenhouse affect is a phenomenon that has recently gained general acceptance by the majority of climatologists and the broader scientific community. The rapid increase in the release of greenhouse gasses (GHGs) which began during the move to industrialisation in the middle of 19th century continues today, as each year we release greater amounts of GHGs into the atmosphere. The overwhelming reason for this is the reliance on fossil fuels to drive the industrialized world's economies, and according to the International Energy Association's (IEA) latest report, this is not a trend that is likely to change much over the next 30 years.[1] In an attempt to tackle the complex and global issue of climate change 189 countries have now ratified the United Nations Framework Convention on Climate change that came into force on March 21st of 1994. In December of 1997 the parties to this convention adopted a new negotiated agreement known as the Kyoto Protocol which entered into force on Feb 15th of 2005. The protocol lists the respective emission reduction targets that each developed country negotiated relative to their 1990 levels. These targets are to be met during the years 2008 to 2012, and vary from a 10% increase in emissions for Iceland, to 8% reductions for the EU, with the cumulative reduction being approximately 5%.[2]

1.1.1 Focus on Canada

Canada was among those countries that ratified the Kyoto Protocol and it agreed to a 6% reduction, a commitment which called on Canada to lower annual average emissions below 563Mt for the 2008-2012 period. This is going to be very difficult for Canada to attain because instead of reducing its emissions, Canadian GHG emissions have actually increased since 1990, with the most recently published numbers revealing 2005 annual emissions of 747Mt. The result of this emission growth is that Canada's Kyoto Gap (the gap between its target emissions for the 2008-2012 period, and its actual emissions) has now grown to over 184Mt, a number which calls for a much more drastic reduction of 25%, as opposed to the previous more manageable 6%.

[1] IEA, 2006
[2] UNFCCC

The largest single contributor to the recent growth in these emissions is the extensive oil sands operations that are taking part in the Western province of Alberta. The oil sands deposits, which are thought to have recoverable reserves of over 173 billion barrels of oil, cover an area over 140 000 square kilometres in central and north-eastern portions of the Canadian province. Unfortunately, due to the poor quality of the oil, and the difficulty in extracting it from the sands, significant amounts of both energy and water are required to produce the final synthetic crude oil. In addition, (and of particular relevance to this study) the mining, processing and upgrading of this oil results in the release of large amounts of GHGs, as well as other air and aquatic pollutants.

With global oil reserves dwindling, and oil prices reaching near record levels, the pressure to develop this vast resource has become immense. This is particularly true given that these reserves lie just north of the world's largest importer of oil, the United States, which has on numerous occasions publicly stated that it would like to reduce its reliance on Middle Eastern oil.

1.2 Rationale for focusing on particular problem area

I was raised in Alberta and developed a keen interest in climate change issues while studying environmental law at the University of Alberta. On a recent trip back to Alberta I was shocked by the extent of the economic boom that is currently underway within the province, one that is due almost primarily to oil sands development. I therefore started to investigate the subject and was struck by the scale of the resources, projects, profits and environment effects. What became increasingly interesting to me was the contradiction that the situation provided; while there is an increasing amount of focus in Canada on reducing it's GHG emissions, at the same time the extremely GHG intensive oil sands operations are being invested in and developed at break neck pace. The focus of the study therefore became investigating possible solutions for reconciling this contradiction.

1.3 Problem Formulation

Due to this immense political and economic pressure, this much is clear: the Alberta oil sands will be developed, regardless of how devastating the environmental effects may prove to be. Thus the focus of this paper is not to question whether the Alberta oil sands should be developed (that ship has already sailed) but instead, how they can be developed in a manner that is line with Canada's environmental commitments. This situation represents a real contradiction for Canada; at a time when it should be reducing its GHG emissions so that it can live up to its treaty commitments, Canada is rapidly expanding oil sands development. In an attempt to reconcile this contradiction, the overarching question guiding this study is therefore:

> How can the Alberta oil sands be developed while at the same time allowing Canada to meet its Kyoto commitments?

The primary method that will be looked at for achieving this goal is the implementation of a large-scale Carbon Capture and Sequestration (CCS) network, particularly CCS in conjunction with enhanced oil recovery (EOR). CCS involves capturing much of the CO_2 that is released when fossil fuels are combusted, and then transporting it to a suitable location for sequestration where it is pumped into the ground, thus preventing its release to the atmosphere where it would otherwise contribute to increasing the concentration of CO_2 in the atmosphere. EOR involves pumping CO_2 into the ground while at the same time increasing conventional oil recovery and it therefore represents a way of reducing the costs of CCS.

1.4 Sub-questions flowing from Problem Formulation

In addition to this central problem formulation, the following nine sub-questions will be addressed throughout the paper:

1) What are Canada's Kyoto targets and why should Canada meet them?
2) Why must GHG emissions associated with Oil sands development be curtailed, why not meet Kyoto targets via other sectors?
3) What are the oil sands, and why 'must' they be developed?
4) What is Carbon Capture and Sequestration, what does it entail?
5) What is the potential for this technology in Alberta?
6) What projects are currently using this technology?
7) What other options exist for reducing oil sands GHG emissions?
8) What hurdles exist to wide-scale implementation?
9) What kind of regulation must be in place as an incentive for it to take place? What (if any) kind of government support must be made available?

The above sub-questions were incorporated into the project design which will be presented in the following chapter. The report aims at following this design by answering each sub-question before moving on to the next, and it thereby serves as the red thread linking the initial questions with the final conclusions.

1.5 Sign posting

- Before addressing the sub-questions, Chapter 2 will first describe the project methodology and design, as well as outline the theories and assumptions underlying the project.
- Chapter 3 addresses the first two sub-questions, namely what Canada's Kyoto commitments are, and why Canada should endeavour to meet them. In addition it explores why GHG emissions associated with oil sands development must be curtailed, as opposed to simply meeting Kyoto targets via other sectors.
- Chapter 4 provides an overview of the oils sands and thereby addresses the third sub-question pertaining to what the oil sands entail, and why it is a near certainty that they will be developed.
- Sub-question four is addressed in Chapter 5 as it focuses on CCS as one of the primary ways in which oil sands producers could potentially reduce their GHG emissions.
- The next two sub-questions are addressed in Chapter 6 as it explores the potential for enhanced oil recovery in Alberta, and what affect this will have on CCS costs. In addition it attempts to verify the cost figures set out in the earlier chapter by way of interviewing various carbon capture and enhanced oil recovery experts, particularly those involved in existing EOR projects.
- Chapter 7 looks at the other viable alternative for oil sands producers to reduce their GHG emissions, that of buying credits, and looks at various scenarios under which this might occur.
- The final chapter addresses sub-questions eight and nine by examining the hurdles that exist to implementing a large-scale CCS network in Alberta, as well as discussing potential incentives or supports that may be required. Based largely on the information gathered from interviews, I will then outline recommendations that could help facilitate the establishment of this network and highlight why work on such a network should be started immediately.

Chapter 2 – Methodology and Underlying Theory

The following chapter outlines the project design and methodology to give the reader an idea of the resources relied upon during the course of the research, as well as how this research will be presented in subsequent chapters. In addition this chapter will detail the relevant assumptions and underlying theory behind the work, as well as highlight some of its potential limitations.

2.1 Work Plan

In an attempt to obtain an overview of the project as a whole, a project work plan was created in the form of a Gannt diagram as recommended by Olsen and Pederson in "Problem-Orientated Project Work".

2.2 Problem Formulation

Having decided upon the problem to investigate, I came up with an initial Problem Formulation fairly similar to the existing one, namely: How can the Alberta Oil sands be developed while at the same time allowing Canada to meet its Kyoto commitments?

2.3 Project Design

To give the investigation some structure a project design was developed based on the sub-questions that flow from the problem formulation, a diagram of which is displayed on the following page. Each sub-question (indicated by the blue boxes) stated the related tasks (green boxes), methods (purple boxes), and desired results (pink boxes) associated with it, and was incorporated into a flow diagram that helped to form the red thread of the project. Like many areas, this topic is quite vast and therefore having the project design laid out beside me helped keep my research on course and focused in the right direction. As the project evolved particular sub-questions were added or deleted in accordance with their relevance to the project.

Figure 2.1
Project Design

2.4 Data Sources - Literature Reviews

While some of the background information was gleamed from textbooks, due to the very contemporary nature of the technologies involved the vast majority of the literature was in the form of recently published reports and articles on websites. In an attempt to incorporate various viewpoints and varying sources I ensured that sources from industry, academia, NGOs and government were all researched and represented in the report.

2.5 Data Sources - Interviews

Interviews were chosen as a means of both supplementing the information found in the literature review and filling in knowledge gaps so the sub-questions could be more adequately answered. As was mentioned above, CCS and Enhanced Oil Recovery (EOR) using CO_2 are relative new technologies and therefore information regarding the latest technologies and cost estimates can only be found by talking to individuals currently working with these technologies. In addition, because a number of those interviewed have worked with these technologies firsthand, their personal opinions and experiences are sources of information that can not be found via literature review.

To collect some background information as to how to proceed with the interviews, I read Steinar Kvale's, 'InterViews' as it came highly recommended from a number of Roskilde University professors and students.

2.5.1 Selection of Interviewees

After conducting a large portion of the literature review, particular areas were sought out for further investigation via interview and ranked according to relevance to the study:

1) An individual with working knowledge of the Weyburn project as this project is the leading EOR CO_2 project in North America.
2) A representative of the ICO2N (Integrated CO2 Network) as it just released a report outlining potential costs of implementing CCS on a large scale in Alberta.
3) An expert on CCS who could shed light on the potential for CCS within Alberta, as well has highlight potential hurdles to its implementation.
4) A representative from the Penn West Energy Trust as it is highly involved in EOR CO_2 projects in Alberta.

5) A representative from Glencoe Resources as it is also involved in various EOR projects in Alberta.
6) Individuals from the major oil companies and oil sands operators such as Syncrude, Suncor, Shell, Petro-Canada, Esso, Chevron, Husky, and Devon.

Potential interviewees were selected according to their respective areas of expertise and were generally names I came across while doing literature reviews of the various subject areas.

The first interviewee was Dr. Stefan Bachu, Senior Advisor Alberta Energy and Utilities Board. He is an expert in the area of carbon capture and geological sequestration, and was recently recognised as a Nobel Laureate for his contribution to the award winning IPCC work. Questions for Dr Bachu pertained to the potential for Carbon Capture and Sequestration in Western Canada, potential hurdles to its implementation, government stances towards it, and incentives that may help facilitate it. The full transcript of this interview, as well as some post-interview thoughts can be found in appendix 1.1.

The second interview was with Shane Silverberg, Manager Investor Relations of Penn West Energy Trust, the largest conventional oil and natural gas producing income trust in North America. It holds the rights to some of the largest potential enhanced oil recovery (EOR) pools in the country, and is one of the very few organisations that is currently involved in numerous EOR projects. Mr. Silverberg was asked the same questions posed to Dr. Bachu, and in addition a number of questions pertaining to EOR within Alberta. The full transcript of this interview can be found in appendix 1.2.

The third person interviewed was Eric Beynon of the ICO2N (Integrated CO2 Network). This network is comprised of various companies from within the energy sector and its aim is the establishment of a CCS network in Canada "committed to helping Canada meet its climate change objectives while supporting economic growth."[3] ICO2N recently released a comprehensive report outlining the potential costs of such a network and Mr. Beynon was one of the lead authors. Mr. Beynon was asked the same basic questions as Dr. Bachu and Mr. Silverberg were, as well as questions pertaining to the findings in the aforementioned ICO2N report. The full transcript of this interview can be found in appendix 1.3.

[3] ICO2N, 2007

The forth interviewee was Dr. Malcolm Wilson, an energy expert at the University of Regina. Dr Wilson is also the director of CO_2 management at the Energy Innovation Network, and was involved in the initiation and development of the International Energy Agency's GHG Weyburn Monitoring and Storage Project. In addition to the standard interview questions, Dr Wilson was also posed a number of questions about the Weyburn EOR project. The full transcript of the interview with Dr. Wilson can be found in appendix 1.4.

The fifth interview was a follow-up interview with Shane Silverberg and its transcript can also be found in appendix 1.2.

Phone calls and/or e-mails inquiring about potential interviews were also sent out to Glencoe resources and all of the major oil companies and oil sands operators in Alberta, however not a single one of these e-mails was met with a reply.

2.5.2 Ethical issues

I was careful to inform potential interviewees of how the information gathered would be used and reported, and asked for their consent in this regard. I offered not to include the interviewee's name, company name, or any other sensitive information as per the interviewee's wishes. In addition, I also offered to provide the interviewees with a copy of the transcribed interview so they had an opportunity to verify its contents before agreeing to have it included.

2.5.3 The Interview situation

Do to the fact that all of the interviewees were located many hundreds (or thousands) of kilometres away it was much more practical for the interviews to be done via telephone. This had a couple of downsides. Firstly it did not allow for any communications via body language which likely resulted in the conversations being a little more formal then a face to face interview, and thus it is possible that the interviewees may have been more candid in a face to face interview. Secondly, because the conversation took place over a speaker phone there were small portions of the interviewee's responses that were inaudible when played back on the recording device. The overall effect of this was quite minimal though, particularly because a number of the interviewees corrected and/or filled in portions marked inaudible when they returned a copy of the transcripts.

2.5.4 Structure of the interview

Kvale writes that the first ten minutes of an interview are critical and I therefore tried to focus on being a particularly attentive listener at the beginning of interviews so the interviewee would feel comfortable opening up during the interview.[4]

The structure of the interviews was what Kvale would describe as semi-structured, as general themes were discussed along with some suggested questions that were provided beforehand. The questions were provided beforehand because some of the subject matter could potentially be quite project specific, and thus I felt that providing the interviewees with these questions beforehand would lead to more complete answers.

2.5.5 Structure of questions

The interviews started with more general or introductory questions so that the interviewee would feel comfortable and could share there own experiences or views on the subject. After came follow-up, probing, and specifying questions where the goal was to learn more about a specific project or detail.

When wording the questions, I was mindful of Kvale's advice, in that the questions should be "short, easy to understand, and devoid of academic language", as this generally helps facilitate a better flow of conversation.[5] However, due to the fact that Kvale's advice is likely not geared towards interviewees that are experts in their particular field (as was the case with the interviewees in this project) this advice was not strictly adhered to as it also had to be balanced with the need to obtain technological and project specific information.

2.5.6 Debriefing

As recommended by Kvale, I was mindful to finish each interview by stating that I had no further questions, and then asked the interviewee if there was anything else he wanted to add as this allowed the interviewee to talk about any ideas or issues that he had been thinking about but not yet touched upon.

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[4] Kvale, 1996 at 128
[5] *Ibid*. at 130

2.5.7 Transcription

The style of transcription used was a narrative one, thus removing many of the repetitions, pauses, and 'hmm's for example. The reason for selecting this style was because the transcripts' intended use was to convey the general views of the interviewees (as opposed to being used for any linguistic or psychological analysis for example, which would generally require a precise verbatim transcription). The result is that the transcripts are more readable, while still maintaining the general views and specific details, facts and figures that were sought-after.

2.6 Discussion of Sources

With respect to the reliability and validity of sources I attempted to validate and cross-reference sources, particularly when including statistics into the project. When I did come across a discrepancy it was generally highlighted and possible explanations were given. The origin and writer of a source was also taken into consideration when analysing a particular piece of information. For example, the Pembina organisation would like to see oil sands development slowed down greatly and have the producers become carbon neutral by 2020. Meanwhile, publications and comments made by the ICO2N network are made on behalf of a group of energy producing companies and therefore there is a different motivation behind their work. Thus I attempted to always be mindful of the various agendas and viewpoints that the various writers and interviewees may have, whether it was an NGO, industrial, government, or academic publication.

2.7 Discussion of Researcher's Point of View and Background

I was raised in Alberta, took degrees in business and law at the University of Alberta and have a number of friends and colleagues working in the Alberta oil industry and therefore am not completely objective with respect to how the slowing of oil sands development may affect their personal welfare. On the other hand, I am also passionate about various environmental issues and am concerned about the environmental effects of oil sands development on both the province, and its contribution to global climate change. In this respect I am once again not completely objective as I feel that the environmental costs of rapid development likely outweigh the economic benefits of exploiting the resource in this manner. In the course of undertaking this project I was aware of how these personal feelings may affect its conclusions and has been careful to be as neutral as possible, and allow the facts to speak for themselves.

2.8 Assumptions

To allow a narrowing in on a more specific problem, certain assumptions were made. Firstly, it was assumed that climate change is occurring, that this change is most likely the result of human induced increases to global CO_2 concentrations primarily brought on by the burning of fossil fuels, and lastly that these changes are likely to result in costly (and/or perhaps catastrophic) changes that should be avoided if at all possible. While I concede that there are still a handful of scientists that feel otherwise, the overwhelming majority of climate scientists now support this theory and therefore the project will proceed based on the assumption that climate change is occurring, and that steps should be taken to halt it.

Another assumption pertained to Canada's stance on Kyoto and the willingness of the Federal government to reduce future emissions. Canada was a signatory to the Kyoto protocol and the previous Liberal government both ratified Kyoto and adopted plans to meet Canada's commitments. A minority Conservative government with its core support stemming from Alberta subsequently come to power and indicated that they will not attempt to meet Canada's Kyoto targets (largely due to fears that this could harm investment in the oil sands). Instead the Conservative government has bound itself to reduce Canada's emissions by setting reduction targets of 20% below 2006 levels by 2020, and 60-70% below by 2050.[6] However this plan is seen by most Canadians and politicians to be too weak, and has even been criticised by the government's own environmental advisory body.[7] In addition, the majority of both the Canadian public and politicians are in favour of Canada meeting its Kyoto targets so it is highly likely that the next election will bring with it a government that is in favour of greater emission reductions. Thus despite the current minority government's stance, this paper is based on the assumption that within the next 10-15 years Canada will at least attempt to reduce its emissions to those levels set out in the initial 2008-2012 Kyoto period.[8] Given growing public concern in Canada, the majority of Canadian politicians supporting such an effort, and what appears to be a future change in US environmental policy (which greatly affects Canadian policy), all signs would indicate that this is quite a reasonable assumption to make.[9]

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[6] Environment Canada, 2008
[7] CBC, 2007
[8] It should be noted that Canada's average emission target for the 2008-2012 period is 563Mt, and based on Canada's 2005 emission figure of 747Mt, the Conservatives pledge to reduce 2006 emissions by 20% would result in a target of 597Mt. Thus even if Canada only aims for the 597 Mt target the scale of the reductions required is almost the same.
[9] Further strengthening the likelihood of this assumption are the thoughts of David Keith, Canadian Research chair in energy and the environment who believes that despite not adopting Kyoto, that the US will place some sort of tax on CO2 within the next five years, and Canada is surely to follow suit. Amey, 2005, at 4

When discussing the GHG emissions associated with oil production the figures in the study refer strictly to the upstream emissions; that is the emissions associated with the mining, producing, upgrading and refining of the oil. The downstream emissions associated with the oil once it has left the refinery and is combusted are reflected in the appropriate domestic GHG emission category, whether it be transportation, heating, or domestic aviation for example.

2.9 A Note on Currencies

Approximately half of the sources relied upon in the writing of this thesis reported figures in US$ while the other half reported in C$. In an attempt to reflect these sources as accurately as possible, figures from sources will always be presented in their original currency. For practical purposes though, because the Canadian and US dollars have been within a couple percentage points of each other for most of 2007 and 2008, any figures from these years can been treated as interchangeable. For the readers reference, the US$ was on average worth 14% more then the C$ in 2006, and 20% more in 2005, and when presenting findings from studies from pre-2007 I will indicate both the currency and the year.[10] Finally, any calculations, assumptions, or arguments made by myself based on pre-2007 figures will have taken these differences into account.

2.10 Limitations

One of the limitations of the study was the inability of the researcher to receive any feedback or interviews from the major oil companies or oil sands producers. Despite the fact I had some personal contacts within a number of these firms, their co-workers were either unwilling or unauthorised to answer any questions or take part in interviews. Some were willing to share some revealing comments strictly off the record, however I was not authorised to include any of this information.

This is likely related to another of the limitations of the study, this being the lack of information on cost estimates for capturing CO_2 coming directly from refineries, power plants and oil sands operators. Due to the fact that CCS technology is still so new, and there is still so much uncertainty about future GHG regulatory regimes in Canada, there is a lot of secrecy regarding potential purchase and selling prices of CO_2 as these operators are reluctant to reveal these costs. This made it difficult to determine precise costs for this technology as I was left to rely mainly on third party

[10] X-rates, 2008

literature. This limitation was slightly mitigated via the interviews as some more precise cost figures were revealed.

2.11 Underlying Themes and Theory

2.11.1 Polluter Pays Principle

The principle underlying much of my paper will be that of polluter pays, that is, if an industry pollutes in the pursuit of profit it should have to pay for it. Known as the Polluter Pays Principle, it was first adopted by the OECD in 1972 as its member countries becoming increasingly aware of the negative effects of pollution.[11] In *Environmental Economics*, Turner, Pearce and Bateman state that "the basic tenet of PPP is that the price of a good or service should fully reflect its total cost of production, including the cost of all the resources used" and in looking at these resources, "the use of air, water or land for the emission, discharge or storage of wastes is as much a use of resources as are other labour and material inputs."[12] In practice what the PPP seeks to do is put a price on the negative externalities associated with an industry. The internalising of these costs can be achieved a number of ways, whether it be via direct government regulation or through the implementing of various economic instruments, such as pollution taxes, charges, or permit systems.[13]

The authors also explain that there are different interpretations of the PPP, including a standard interpretation and an extended one. What they refer to as the 'standard interpretation' requires industry to pay for the cost of reducing emissions to a certain level. However in this case the firm is not responsible for any environmental damage that may occur as a result of these 'acceptable' emissions. In essence this interpretation of the PPP allows industry to pollute for free, but only up to a particular level.[14] The other interpretation presented by the authors is the 'extended interpretation' which again calls for industry to pay the costs of keeping emissions down to a certain level, but in addition requires industry to pay for the damages associated with the 'allowed' pollution. The latter of the two interpretations is more comprehensive as it makes industry responsible for all the damages caused by emissions associated with the production of a product. Under the standard interpretation, unless there is an option to sell unused emissions to other firms, the polluting firm has no financial incentive to reduce emissions lower then the proscribed maximum. This is not the case with the extended interpretation which would assign a cost based on

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[11] Turner, 1993 at 145.
[12] Ibid.
[13] Ibid.
[14] Ibid.

the amount of emissions, and therefore economists point out that this interpretation is more likely to motivate polluters to switch to less polluting technologies.[15] In either case, combining an emission limit with an emission trading system is more cost-effective for industry as a whole, because it would result in the least emission intensive firms selling their emission allowances to the more emission intensive firms, but overall emissions would still be no higher then the proscribed limit.

In many other areas of industry this principle has been embraced and recognised, for example in the polluting of lakes and streams, or the release of hazardous materials. Up to this point, the release of these 'otherwise harmless' GHGs by industry has not been regulated in Canada and therefore industry has not been held accountable for these negative externalities. By ratifying the Kyoto agreement Canada has recognised that these GHGs do carry an environmental burden and must be reduced. Just how to go about making these reductions has been the subject of much debate, however it would seem just that those who profit from producing these emissions should be responsible for the costs associated with their reduction, and thus implementing the PPP in the case of GHG emissions is appropriate.

2.11.2 Cost effectiveness and Equity

Other underlying themes will be that of cost effectiveness and equality. In defining what is the 'best' approach to reducing GHG emissions while allowing oil sands development, the primary focus will be on what is the most cost-effective approach; however this will also be tempered by the notion that any actions should not be unduly arduous for particular producers to implement.

As the oil sands operators are all privately owned entities their primary objective is to maximise profits. If they are required to reduce their GHG emissions they will of course attempt to do so in the least costly fashion and therefore the main criteria for determining the appropriate strategy for reducing their emissions will be cost effectiveness.

In applying the PPP, attempts should be made to do so as equitably as possible so that its implementation does not unduly harm one firm with respect to another. This is of importance because the goal of implementing PPP is not to distort the market or favour one firm over another, but instead to alter the behaviour of its participants so that overall oil sands GHG emissions can be reduced.

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[15] *Ibid*. at 150

2.12 Chapter Summary:

Having dealt with how and why I went about researching this particular topic, as well as outlining themes such as PPP and cost-effectiveness which will underlie the report, Chapter 3 will now turn to the first two sub-questions regarding Canada's GHG emissions and Kyoto targets.

Chapter 3 – Canada and Kyoto

The focus of this chapter is twofold; firstly it will detail what Canada's Kyoto commitments are, as well as put forth arguments as to why Canada should endeavour to meet them, and secondly it will outline why it is that GHG emissions for the oil sands in particular should be curtailed.

3.1 Canada's Kyoto Commitments - How much?

When looking at the main research question, the first sub question that comes to mind is: What are Canada's Kyoto targets? By signing and ratifying the Kyoto Protocol, Canada agreed to reduce its 1990 CO_2e emissions of 595Mt by 6% in the first Kyoto period. In practical terms this means that the average annual Canadian emissions from 2008-2012 must be below 563Mt for Canada to be in compliance with its Kyoto commitments. However, since 1990 Canadian emissions have continued to increase, with the most recent published numbers revealing 2005 annual emissions of 747Mt. The result of this is that Canada's Kyoto gap (the difference between its target emissions for the 2008-2012 period of 563Mt, and its actual emissions of 747Mt) is now over 184Mt. Thus while the question of much Canada must reduce is straight forward enough, the question of why Canada should endeavour to meet these constantly increasing targets is more complex.

3.2 Canada's Kyoto Commitments - Why?

There are a large number of reasons why Canada should respect its Kyoto commitments, ranging from those which embrace the principles of fairness and equality, to those which are more self-serving in nature.

3.2.1 Responsibility for Current Predicament

Human induced climate change is largely caused by the burning of fossil fuels such as coal, oil, and natural gas. The carbon within them becomes oxidized forming carbon dioxide, which is released into the atmosphere and remains there for a prolonged period of time where it contributes to the naturally occurring greenhouse effect. While CO_2 is the main culprit, there are a number of other GHGs which vary both in the time it takes for them to break down, as well as their contribution to global warming.

When we refer to global climate change it is important to remember that due to the length of time it takes before a GHG is broken down or absorbed, it is the cumulate emissions over the last 100 years that is of critical importance, not just recent annual emissions. According to the World Resource Institute's emission database, from 1900 – 2003 Canada was responsible for 2.19% of global cumulative emissions, a staggering amount when we consider that Canada is home to under 0.50% of the global population.[16]

Those who claim that nations such as Canada, the United States and Australia should not have to meet their Kyoto commitments until developing nations such as China, India and Brazil agree to similar reductions very conveniently overlook this point. Simply put, the climate change currently taking place is overwhelmingly due to the cumulative emissions of developed nations, and therefore countries such as Canada whom bare the most responsibility are precisely those that should show leadership and meet their commitments.

3.2.2 Emissions Per Capita

In per capita terms Canada has faired no better in recent years, as its 23.1 tonnes of CO_2e carries the very dubious distinction of being the world's second largest GHG emitter per capita, trailing only the United States.[17] Per person, each Canadian emits over four and a half times as much as their Chinese counterparts, nine times as much as Brazilians, and roughly fifteen times as much as the average person in India.[18] These figures further undermine the argument that developing nations must agree to make reductions before developed countries do so, as it is clearly countries such as Canada that are still the worst culprits, and as such they should honour their Kyoto commitments.

3.2.3 Ability to Pay

In addition to the concept of responsibility outlined above, the 1992 Framework Convention on Climate Change agreement (which Canada has signed and ratified) recognised that the notion of capability must be taken into consideration when determining who should make emission reductions. This implies that wealthy developing countries should take a leadership role and make the majority of the initial emission reductions as they have the greatest means to do so. According

[16] Data provided by the Climate Analysis Indicators Tool
[17] These are based on 2005 figures and exclude tiny states with less than 0.5% of global emissions such as Qatar, Kuwait, United Arab Emirates, etc. Environment Canada, 2007
[18] Based on 2003 figures.

to the 2007 CIA factbook, in 2006 Canada had the 16th highest per capita GDP in the world and thus easily qualifies as a developed nation that has the fiscal ability to reduce its GHG emissions.

3.2.4 Self interest

Aside from admirable notions such as taking responsibility for ones own actions, there exist other reasons why it would be in the best interest of Canada to see climate change halted. As global GHG emissions continue to rise, scientists studying the climate speculate that the average world temperature will rise by somewhere between 1.4 and 5.8ºC over the coming century, increases which could be associated with further shifts in weather patterns.[19] These include fluctuations in levels of precipitation, ferocity of precipitation, cloud cover and extreme temperatures, as well as increased melting of sea-ice, continued raising of sea levels, and numerous other effects, both expected and non-expected.[20] Of particular relevance to Canada is the fact that these increases in temperature are not anticipated to be constant across the globe, but instead are expected to affect coastal and Northern countries to a much greater extent. The greatest changes are anticipated to occur in the Arctic, where studies predict increases even larger then the 1.4-5.8ºC noted above, temperature shifts which would completely altar eco-systems and people's way of life.

According to the government of Canada's: *Climate change, Impacts and Adaptation, a Canadian perspective*, climate change could pose a number of potential benefits and drawbacks for Canada.[21] Some potential benefits listed included: an extension of the growing season for agricultural products, increase in certain crop yields (grain and corn in the Maritimes, and canola in Alberta), less traffic accidents and lower costs associated with the maintaining of roads during the winter. Meanwhile, associated drawbacks include: increased insect, water and heat wave problems leading to lower crop outputs, a rise in the sea level resulting in enormous property loss, a reduction of the great lakes water level, greater soil erosion, increased storm frequency and ferocity, and increased costs of health care. Possibly of greatest concern is the melting of artic ice, a phenomenon we are already beginning to observe. This results in great difficulties for northern wildlife, particularly polar bears, which are seeing their habitat literally melt away. A related issue is that of the Northwest Passage, which as the ice continues to melt will become increasingly unproblematic to navigate. This poses a significant potential risk to Canada, as the development of a major shipping

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[19] IPCC, 2001 at 8
[20] Warren, 2004 at viii
[21] *Ibid.,* at xx

lane through Canada may challenge its sovereignty over the region, and greatly increase maritime pollution.

The potential for these benefits and setbacks varies greatly between regions and sectors; however the Canadian government study concludes that the net impact will result in the negative consequences outweighing the positives and thus even for selfish reasons it is in Canada's long-term interests to help curb climate change.

3.2.5 Respectability

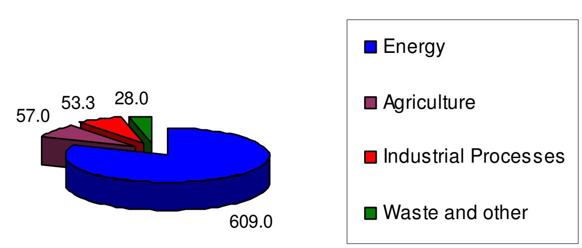
In addition to the historical, moral and national reasons for meeting its commitments are the issues of pride and respectability. Canada was once a forerunner in the environmental arena and is a country that prides itself on its pristine nature and clean environment. By meeting its Kyoto commitments Canada would take a big step in both returning to this role, and legitimising this claim.

3.3 Reduction of Oil Sands Emissions

Moving forward on the basis that Canada will meet its Kyoto commitments, the question then becomes why focus on oil sands emissions? At a time when global demand for oil is increasing, and oil stocks are in decline, why not meet Kyoto targets via reductions in other sectors?

3.4 Overview of Canada's GHG emissions

Figure 3.1 – Canada's 2005 GHG Emissions by Sector (Mt of CO_2e)



To gain a better understanding of where potential reductions could be made a brief overview of the sector emissions will first be provided. As can be seen from Figure 3.1, over 609Mt, or 81% of 2005 emissions, were from the energy sector while Agriculture and Industrial Processes were next with only 7.6% and 7.1% respectively. The remaining 3.7% were from waste and other residual sectors, and due to their small proportion of overall emissions will not be further examined within this report.

3.4.1 Agricultural and Industrial Processes

Of the 57Mt of agricultural emissions in 2005, the majority is associated with the release of CH_4 from beef and dairy cattle. As these are naturally occurring releases, substantial reductions in this sector can only be made via drastically reducing beef farming in Canada, a very unlikely and drastic step to reduce some 20Mts of CO_2e.

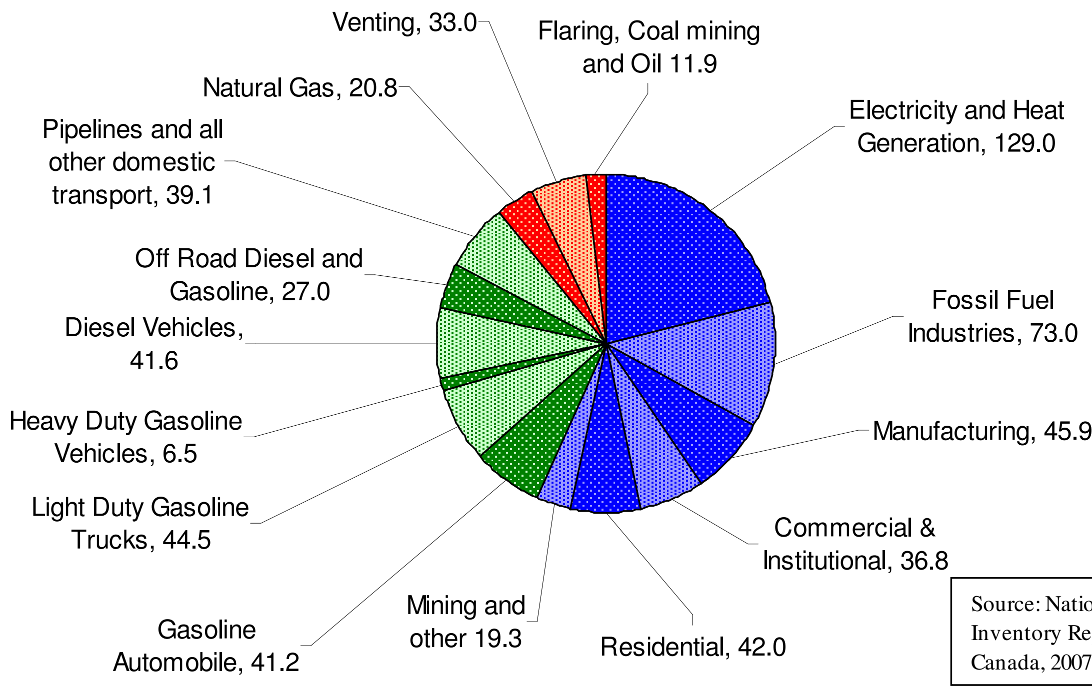
The industrial processes sector includes emissions from the production of ammonia, nitric acid, adipic acid, ferrous metal, aluminium, magnesium, as well as those related to the production and/or consumption of halocarbons and SF6.[22] It however does not include the emissions related to the energy used as an input in these processes; these emissions are found within the energy sector. Since 1990, total emissions from the industrial process sector have actually decreased by a little less then half a percent, this despite large percentage increases occurring in some sub-sectors due to greater cement production and the use of HFCs instead of CFCs.[23] This is because increases have been more then offset by reductions largely attributably to reduced use of limestone in pulp and paper mills, as well as a variety of emission reduction programs and technologies that have been implemented throughout this sector.[24] Thus while there do exit some opportunities for reductions (particularly in the area of HFC use), the industrial processes sector is not a viable option for large-scale reductions of the kind needed for Kyoto compliance.

3.4.2 The Energy Sector

With over 81% of Canada's 2005 emissions, and substantial reductions in other sectors looking unlikely, the energy sector is the area where the majority of reductions will have to be made. Figure 3.2 reveals the makeup of this sector as broken down by Environment Canada in its most recent National Inventory Report submitted to the UN Framework Convention on Climate Change in April of 2007. In this report the energy sector was subdivided into three main areas: Transportation (200Mt and depicted in green), Stationary sources (346Mt encompassing all the blue coloured wedges), and Fugitives (65.7Mt in the form of the three red triangles).

[22] Environment Canada 2007, at 91
[23] The replacement of CFCs with HFCs (and their much higher GHG equivalent) is largely due to industry conforming to the Montreal Protocol which banned the use of CFC's. *Ibid*., at 98
[24] *Ibid.*

Figure 3.2 – 2005 GHG Emissions within Energy Sector (Mt of CO_2e)



Source: National Inventory Report. Canada, 2007

3.4.2.1 Transportation Sector (200Mt)

The transport sector incorporates emissions associated with fossil fuel used for domestic aviation, domestic marine, railways, road transportation, off-road vehicles, and pipelines. A chart detailing the 1990 and 2005 emissions can be seen on the following page (due to rounding some totals may not add up exactly). GHG emissions from transport activities in the mining, oil and gas, agriculture and forestry sectors are also included here, and are to be found in the 'other transportation' category in Figure 3.3.[25]

In a fifteen year period, the transportation sector has seen a 33% increase in its GHG emissions, from 150 Mt in 1990 to nearly 200 Mt in 2005, thus ranking as the second largest GHG category in Canada.[26] The two main culprits appear in red text in figure 3.3 and are a) increased freight transport via heavy duty-trucks and b) a higher proportion of light trucks and SUV's being used for personal transport. Both of these areas represent opportunities for future reductions, particularly personal vehicles.

[25] *Ibid.,* at 60.
[26] *Ibid.,* at 46

Figure 3.3 – Transportation Emissions by Source

GHG Source Category	GHG Emissions (kt CO_2e)			
	1990	2005	Change	% Change
Total Transport	**150 000**	**200 000**	**50 000**	**33%**
Civil Aviation (Domestic)	**6 400**	**8 700**	**2 300**	**36%**
Total Road Transportation	**101 000**	**135 000**	**34 000**	**34%**
Light-Duty Gasoline Vehicles	47 200	41 200	- 6 000	-13%
Light-Duty Gasoline Trucks	21 300	44 500	**23 200**	**109%**
Heavy-Duty Gasoline Vehicles	8 050	6 510	- 1 540	-19%
Motorcycles	151	260	109	72%
Light-Duty Diesel Vehicles	363	443	80	22%
Light-Duty Diesel Trucks	724	2 200	1 476	204%
Heavy-Duty Diesel Vehicles	21 200	39 000	**17 800**	**84%**
Propane & Natural Gas Vehicles	2 200	720	- 1 480	-67%
Railways	**7 000**	**6 000**	**- 1 000**	**-14%**
Navigation (Domestic Marine)	**5 100**	**6 500**	**1 400**	**27%**
Other Transportation	**30 000**	**40 000**	**10 000**	**33%**
Off-Road Diesel	20 000	20 000	0	0%
Off-Road Gasoline	7 000	7 000	0	0%
Pipelines	6 900	10 100	3 200	46%

Source: National Inventory Report: 2007

Despite the fact that the number of light-duty gasoline vehicles on the road increased slightly since 1990, the amount of kilometres driven in such vehicles decreased. Coupled with efficiency improvements this resulted in a 6Mt (13%) decrease in such emissions. Overall however, the amount of total passenger kilometres increased during the 1990 to 2005 period, and the number of light-duty gasoline trucks on the road (a category that includes vans, pickups and SUV's) more then doubled. Due to the fact that that these light-duty gasoline trucks on average emit 40% more then their light-duty counterparts, total emissions from this category rose by over 23Mt, an astounding 109% increase in just fifteen years. [27] According to the National Inventory report almost 2.5Mt of emissions were purely the result of private individuals shifting from automobiles to SUVs, vans and pickups. In addition, the report indicates that a trend towards greater horsepower for all classes of personal vehicles has resulted in transport emissions being much higher then they would otherwise have been. In fact, the report states that the rather substantial gains made in other areas such as

[27] *Ibid.*, at 47

efficiency improvements in power plants have been all but negated by these additional horsepower related emissions. [28]

The transport sector is without doubt one of the areas where substantial emissions can (and must be) made. In the personal transport sector alone it would appear that reductions greater then 20Mt could easily be achieved within a relatively short time frame, particularly if the proper incentives to use more fuel efficient vehicles were put in place.

3.4.2.2 Stationary Sources (346 Mt)

3.4.2.2.1 Public Electricity and Heat Production

By far the largest producer of GHGs in Canada, the public electricity and production category was responsible for the release of 129Mt in 2005. This category involves emissions related to the production of electricity from the combustion of fuel in thermal power plants, and since 1990 this area has seen large increases in both absolute (33Mt) and percentage terms (35%).[29] Of greater concern is the fact that total energy generation has meanwhile only increased by 28%, which means that this sector was more GHG intensive in 2005 then 1990. This was because the additional electricity demand was met primarily with fossil fuel based technologies such as coal. This is reflected in the fact that hydropower saw its proportion of electricity production fall from 63% in 1990, to 60% in 2005, while fossil fuel increased by a corresponding amount, from 22% to 25%.[30] On a positive note, coal related GHG emissions appeared to peak in 2003 and have been decreasing since due to the usage of better coal and the switching of some plants to natural gas. Furthermore, while not yet a significant portion of the overall electricity generation mix, increasing amounts of renewables (particularly wind) have been installed in recent years, a trend that is likely to continue.[31]

If Canada is going to meet its Kyoto commitments there is no question that this category must see dramatic reductions. There exist a number of options for such reductions including the increased reliance on renewables, as well as the use of carbon capture and sequestration in conjunction with coal-based power plants, a technology which will be examined later in the paper.

[28] *Ibid.,* at 13
[29] *Ibid.,* at 44
[30] *Ibid.*
[31] *Ibid.*

3.4.2.2.2 Manufacturing Industries, Construction, and Mining

Incorporating emissions associated with the combustion of fossil fuels in the iron, steel, metals, chemicals, cement, pulp, paper, print, and construction, and mining industries; in total this category was responsible for 63Mt of emissions in 2005.[32] From 1990-2005 the iron, steel and non-ferrous metals industries emissions have remained almost the same, the construction, chemicals and pulp and paper emissions have decreased by over 25% each, while cement emissions have increased by 24%. Despite the fact that the mining sector has increased emissions by 152% (thus bringing their 2005 output to 15.6Mt) many other sub sectors decreased their emissions, and as a whole emissions from this sector have remained largely unchanged.[33] The result is that while there still exist options for moderate reductions, more dramatic reduction opportunities are likely to be found elsewhere.

3.4.2.2.3 Residential and Commercial

This category covers the emissions produced when fossil fuels are combusted to heat and/or cool residential and commercial buildings. 2005 saw 36.8 Mt of CO_2e being emitted for commercial/institutional use, while 42.0Mt were associated with residential use. Since 1990 the commercial emissions have gone up by 11Mt, an increase of 43%, meanwhile residential emissions have come down 2.7%, or 1.2Mt.[34] Both areas saw large increases in both the amount of floor space and appliances and equipment used. Despite this, residential emissions decreased due to fuel substitution, and efficiency improvements. In addition to the increased floor space, commercial emissions increased because a greater percentage of floor space was office as opposed to warehouse, with office space having greater heating and cooling needs.[35]

Given advances in building technology, both of these areas represent opportunities where reductions can be made, particularly the commercial side which has seen large increases since 1990. However, given that the current total is under 78Mt, even a 20% reduction would still require very large reductions to be made in other areas as well.

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[32] *Ibid.,* at 45
[33] *Ibid.*
[34] *Ibid.,* at 49
[35] *Ibid.,* at 50

3.4.2.2.4 Petroleum Refining and Manufacture of Solid Fuels and Other Energy Industries

This category can essentially be split into two areas, the GHGs emitted from the combustion of fossil fuels in the refining process, and the GHGs emitted from the combustion of fossil fuels used to procure and manufacture fossil fuels (often referred to as upstream oil and gas emissions).[36] The emissions associated with refining were 16 Mt in 1990, and 18Mt in 2005, an increase of roughly 18%. Emissions from the manufacture of solid fuels and other industries saw a much larger increase of 53%, as emissions went from 36Mt to 55Mt in the same time period.[37] This increase is largely due to the fact that emissions associated with the upgrading of crude bitumen to synthetic crude are included in the latter category, a trend that is only likely to accelerate if changes are not made in the Alberta oil sands industry.

3.4.2.3 Fugitive Emissions (65.7Mt)

This category includes the fugitive releases of GHG associated with both the coal mining and handling industry, and the oil and natural gas industry. However, the fugitive emissions from coal mining makes up only 1% of this total, and therefore the focus will be on the fugitive emissions from the oil and natural gas industry. In the *National Inventory Report* these fugitive emissions are defined as those emissions "associated with the fossil fuel industries (that) are the intentional or unintentional (i.e. accidental) releases of GHGs that may result from production, processing, transmission, and storage activities."[38] Included in these fugitive emissions are those related to flaring activities because the purpose of flaring is not to "produce heat or generate mechanical work."[39] From 1990 to 2005, oil and gas fugitive emissions increased by 59%, bringing 2005 totals up to 65.0Mt. To put this increase into perspective, this is the largest percent increase for any category in the energy sector.[40]

3.5 Total emissions related to the Oil and Gas industry

Given that 99% of the fugitive emissions come as a direct result of oil and gas industry operations, we can essentially add these oil and gas fugitive emissions (65 Mt) to those from the manufacture of fossil fuels above (55 Mt). This 120 Mt sum gives us a more accurate picture of the total emissions

[36] *Ibid.,* at 45
[37] *Ibid.*
[38] *Ibid.,* at 60
[39] *Ibid.*
[40] *Ibid.,* at 43

associated with the procuring and extracting of fossil fuels in Canada, and it represents over 16% of Canada's total 2005 emissions. Interestingly enough, the majority of these emissions were not associated with fossil fuels that were used *in Canada*. This is because 2005 saw 73 Mt of GHG emitted in Canada for the production, processing, and transmission of oil and gas for export, a figure that is up 162% since 1990.[41]

3.6 Focus on Oil Sands Emissions

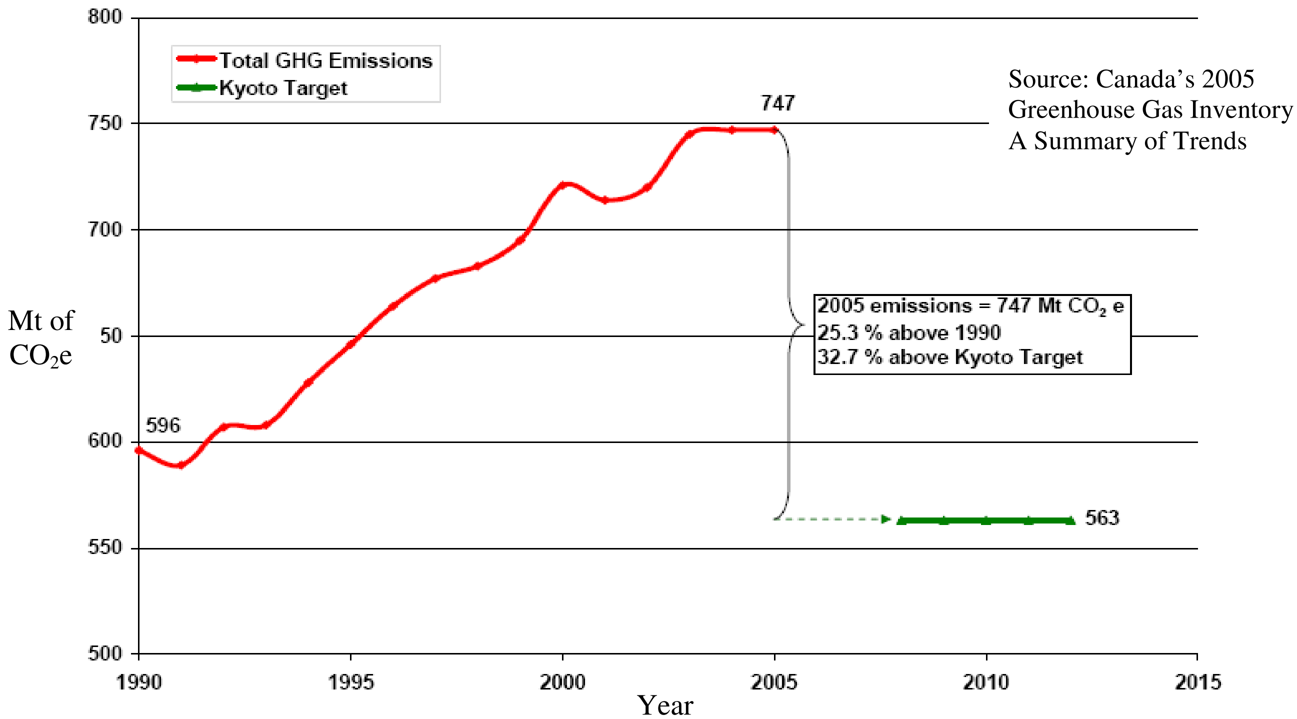
This chapter set out to determine what Canada's Kyoto commitments are, why it should endeavour to meet them, and why the GHG emissions from oil sands operations in particular should not be allowed to increase. The first two questions were addressed in the first portion of the chapter, while the brief overview of Canada's GHG emissions by sector provides the background for analysis regarding the third question.

3.7 Equity and Severity of Kyoto Gap

Canada's emissions since 1990, as well as its average Kyoto commitment of 563Mt, are shown on the following page in Figure 3.4. The difference between these two figures, 184 Mt of CO_2e, is referred to as the 'Kyoto Gap' as it represents the gap between where Canada's emissions should be by 2008-2012, and where they are as of the most recent 2005 figures. In practical terms, this means that 2005 emissions will have to be reduced 24.6% by the 2008-2012 period. Given the challenges that Canada will face in reducing this rather substantial gap to zero, all sectors within the country must make reductions, particularly those from the energy sector which dominates Canada's GHG emissions. By 2007, emissions from oil sands plants alone are likely to be around 40Mt, resulting in the industry being responsible for the largest single portion of GHG emission increases.[42] The reason for this is that the production of synthetic oil from the oil sands is approximately three times more GHG intensive then conventional crude.[43] Therefore allowing the oil sands sector, one of the largest energy sub-sectors, to continue polluting unabated is not a viable option. Incorporated into this rational is the principle of equity highlighted in chapter 2; if other sectors have to make reductions, then it would only seem equitable that the oil sands sector should do the same.

[41] *Ibid.,* at 15
[42] Deyer, 2007 at 9
[43] *Ibid.*

Figure 3.4 – Canada's 'Kyoto Gap'



<u>3.8 Polluter Pay and Ability to Pay Principles</u>

If we recall from Chapter 2, the main idea behind the Polluter Pays Principle is that the price of a good (in this case a barrel of oil) should reflect the cost of all the resources used to produce the product, *and* the costs relating to emissions or discharges that occurred as a result of its production. Up until recently industry could release CO_2 into the atmosphere freely as there was not yet a consensus that such emissions were potentially harmful. With the majority of climatologists now pointing the finger directly at the increase in GHG emissions as the reason for global warming, these emissions which were before seen as relatively harmless have now fallen into the category of an emission or discharge that according to the PPP must be factored into the price of a good.

One of the principles set out by the UNFCCC is that of 'ability to pay', a principle that is very applicable where the oil sands are concerned. The GHG emissions associated with oil sands production are a result of crude bitumen being mined and upgraded for profit, and the large oil companies which own these operations are currently experiencing record profits. If the principles of polluter pays, and ability to pay are to be applied, then these oil companies should be responsible for the associated GHG emissions, and undertake measures which will reduce them.

3.9 Chapter Summary

If Canada is to meet its Kyoto commitments at some point within the next 10 – 15 years it must make reductions of over 184Mt, and as the various sector breakdowns above outline, the majority of these will have to take place within the energy sector. The oil and gas sector, and the oil sands producers in particular, are responsible for a substantial portion of these total emissions, as well as an even larger portion of emissions growth. When the principles of polluter pays and ability to pay are incorporated, then it becomes increasingly apparent that these firms (which are currently earning record profits) should be responsible for large emission reductions. Chapters 5 and 6 will go into more detail with respect to just how oil sands producers could reduce their emissions. However, before turning to that question, Chapter 4 will first take a closer look at what the oil sands entail, and address the question of why a resource with such enormous potential environmental problems is being developed in the first place.

Chapter 4 – Oil Sands

The purpose of this chapter is to provide an overview of the oils sands and try to give a sense of both the scale of the resource and the potential environmental problems their development may lead to. In so doing it will look at the potential revenues, costs, and technologies associated with their development, as well as highlight potential technologies that may help mitigate some of these negative externalities.

4.1 What are oil sands?

The term 'oil sands' (or 'tar sands') is used to describe a dark coloured mixture consisting of crude bitumen and sand, rocks, clay, silt, or other minerals. The crude bitumen itself is a heavy form of oil with a high density and viscosity. This means that it does not flow well and therefore can not be sent via pipeline in its natural state.[44] In addition to its high viscosity, another trait that makes oil sands distinct from conventional oil is that they are located very close to (and even right at) the surface, and thus they require different extraction techniques then that of conventional oil. If the depth to the bitumen mixture is less then 75-100 meters then it is generally surface mined via a massive open-pit mine. The mined mixture is then hauled to an extraction plant where the bitumen is separated from the sand and clay.[45] For deeper deposits 'in situ extraction' is undertaken whereby steam, water or other solvents are injected into the ground via one well, and the now heated bitumen flows to another well where it is pumped out.[46]

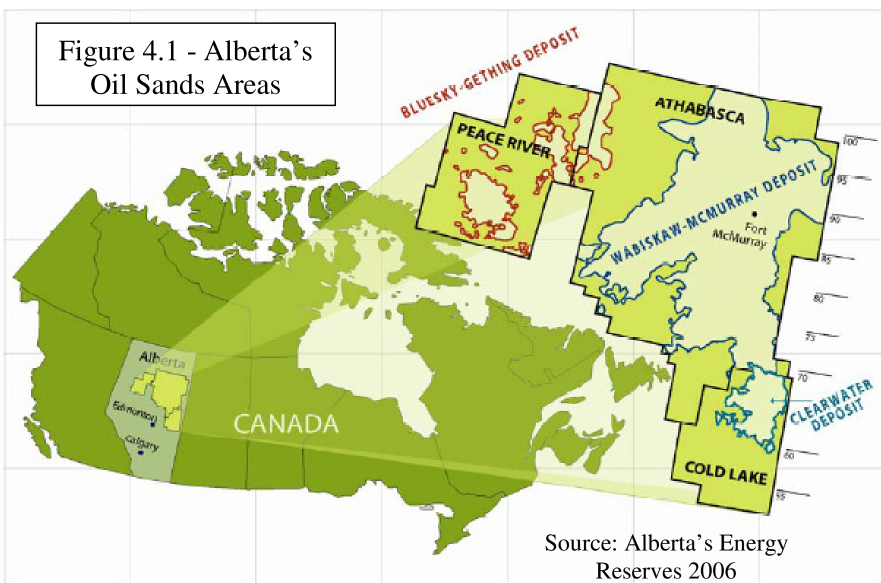


Figure 4.1 - Alberta's Oil Sands Areas

Source: Alberta's Energy Reserves 2006

[44] Deffeyes, 2005 at 102
[45] Woynillowicz, 2005 at 11
[46] The two predominant in situ extraction techniques will be explained in greater detail later in the chapter.

As outlined in Figure 4.1, the Western Canadian oil sands are located in the north-eastern portion of Alberta in three areas: Athabasca, Cold Lake, and Peace River. Cumulatively, these three zones comprise an area over 140 000 km^2, or to put in relative terms, a land mass more then three times larger then all of Denmark![47]

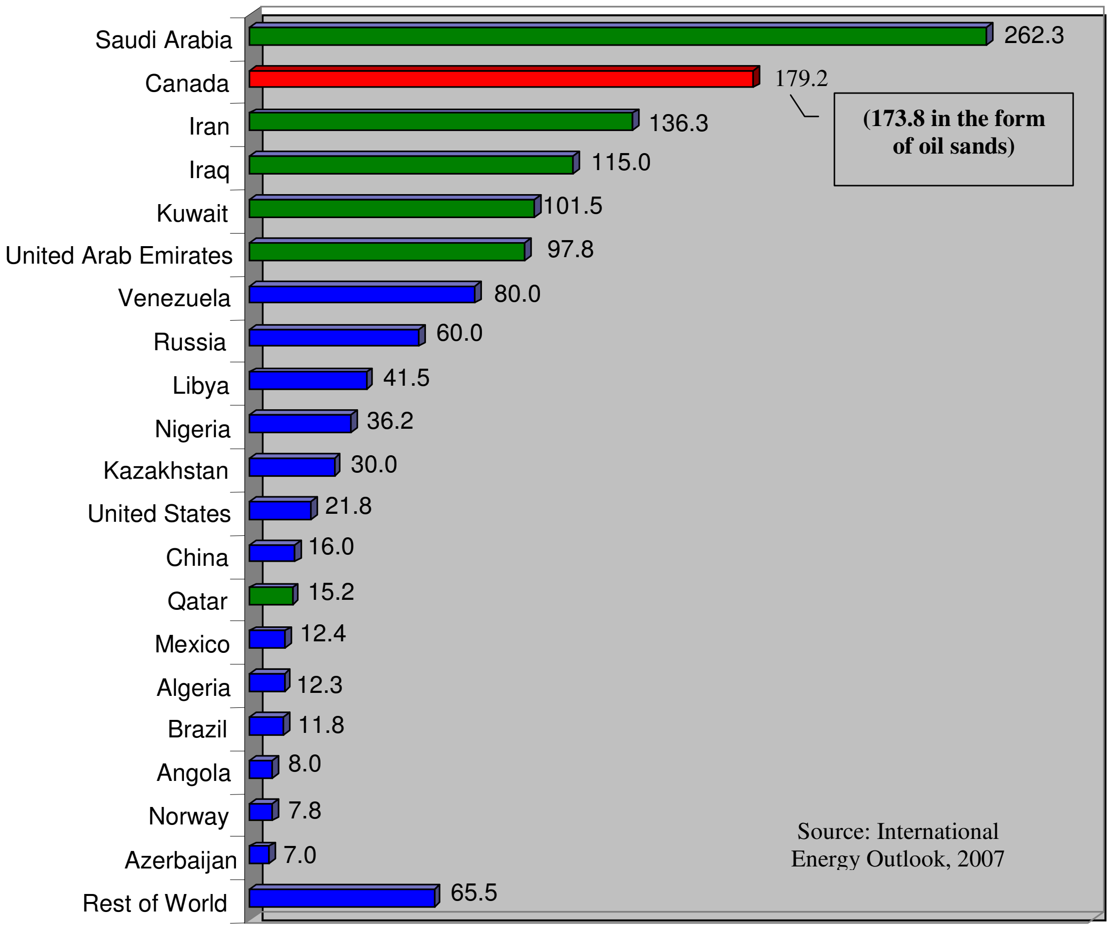
4.2 What's all the fuss about?

The primary reasons that the Canadian oil sands are garnering such much interest is because: 1) oil prices continue to increase (an issue that will be discussed later in the chapter), and 2) due to the sheer scale of the resource. Given current technologies and anticipated economic conditions it is estimated that approximately 10% of the crude bitumen within the Alberta oil sands areas can be recovered in the foreseeable future, while as much as 19% may eventually be extracted. This 10% figure may not sound too impressive, but when we consider that there are an estimated 1.7 *trillion* barrels of crude bitumen deposited within these three areas, then 10% becomes an awfully large number.[48] As recently as its 2004 edition, the International Energy Agency's World Energy Outlook reported that Canada's oil sands were not considered 'proven reserves' by many of the leading oil and gas journals, and thus Canada was outside the top 15 on the global list in terms of proven reserves.[49] Figure 4.2 on the following page reveals how much this has changed in just a short period of time.

With over 13.5% of the worlds proven oil reserves, Canada now finds itself with reserves in excess of 173 billion barrels, second only to Saudi Arabia. These massive reserves (of which the oil sands represent more then 96%) are geographically well placed as they are located just north of the world's largest importer of oil. Thus it should come as no surprise that the United States, who have repeatedly stated that they wish to reduce their dependency on Middle Eastern oil (depicted in green below), have expressed great interest in the rapid development of the Alberta oil sands.

[47] EUB, 2007 at 23
[48] Woynillowicz, 2005 at 1
[49] IEA, 2004 at 91

Figure 4.2 - World Oil Reserves as of Jan, 2007
(Billions of Barrels)



4.3 Early History

As parts of it were located at surface level along the banks of the Athabasca River, the original First Nations people of Western Canada were well aware of the tar sands in what is now North-eastern Alberta, yet they could likely never have imagined the value that future generations would put on this vast resource.[50] Although the first scientific studies regarding the tar sands were published in 1820, it was not till 1906 that the first serious attempt was made to develop the tar sands commercially.[51] Unfortunately for well driller Alfred von Hammerstein, the first wells drilled between 1906 and 1917 were done under the assumption that the tar sands must be the result of large pools of oil located underneath. Although a reasonable assumption at the time, it proved to be

[50] Deffeyes, 2005 at 102
[51] *Ibid.*

incorrect and thus none of his approximate twenty-four wells, or any others conducted in the area up till as late as 1930, proved successful in striking oil.[52]

In the meantime, others began mapping the exposed oil sands and experimenting with various methods to separate the bitumen from the sand. Although a few techniques proved successful in removing the bitumen (most involved some variation of heating the substance with a water mixture, then skimming the oil off the top) they were still not commercially viable.[53] One of these early researchers was Dr. Karl Clark of the Alberta Research Council (established in 1919), who developed a process for separating bitumen from the sand in 1923. Clark and others continued their work in the area, and in 1944 the Alberta government and Oil Sands Ltd partnered to build a pilot plant North of Fort McMurray.[54] The site, apply named Bitumount (recall that crude bitumen is the technical term for the oil extracted from tar sands), was initially projected to cost $250 000 and was home to a great deal of further testing and research. However, in 1948 when the actual construction costs had doubled, Oil Sands Ltd left the partnership as they did not have the necessary funds.[55] When entering into the project, the intention of the government had been to determine the production cost of this particular bitumen, not to operate a plant commercially, and thus despite having shown that crude bitumen could be extracted from the sight at a commercially viable cost as early as 1949, the government sold the site in 1954.[56]

In the same region but at another site, the first major commercial development was undertaken in 1967 by the Great Canadian Oil Sands Company (now Suncor) with the establishment of a large open pit mine.[57] The other major player to arrive on the scene was Syncrude, who in 1973 partnered with the Alberta government via the Alberta Energy Company (AEC). In return for its equity investment, the AEC received an 80% stake of a pipeline, and 50% stakes in both Syncrude's plant and power facility.[58] The following years provided the two companies with numerous difficulties as they attempted to reduce the enormous operating costs of producing the synthetic crude in a region where infrastructure and equipment must be able to cope with temperatures that can drop below - 40ºC in winter.

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[52] Barnett
[53] *Ibid*.
[54] Woynillowicz, 2005 at 2
[55] *Ibid.*
[56] *Ibid.*
[57] *Ibid.*
[58] *Ibid*.

By 1986 the per barrel production cost had been reduced from C$35 to C$13, but the process was still inherently risky and not a very profitable venture.[59] This was soon to change though, because in 1995, working under a mandate given to them by the Alberta Chamber of Resources, the National Oil Sands Task Force (a group consisting of representatives from government and the oil industry) released *The Oil Sands: A new Energy Vision for Canada.* The primary goal of this task force was the tripling of oil sands production by 2020, and included were many recommendations about how best to bring this about. Improving the public perception towards the tar sands was one of them, and thus the sands were no longer referred to as 'tar sands', but now 'oil sands' as this was thought to be more appealing to the public.[60]

4.4 Tax Breaks and Royalty Incentives

In Canada, natural resources such as oil are not owned by the energy companies, but by the citizens of the province and are administered on their behalf by the provincial government. In Alberta this responsibility falls to the Department of energy, which leases energy companies the right to procure, extract and sell these natural resources.[61] In a sense the oil companies are acting as an agent for the owners of the oil (the Alberta citizens) by extracting and selling the oil on their behalf, and as such are entitled to a portion of the revenue generated. The portion that is retained by the province on behalf of its citizens is referred to as a royalty, and exactly how this royalty rate is calculated varies greatly throughout the world. Of the recommendations made by the National Oil Sands Task Force that were adopted, one of the most important in terms of driving future oil sands development was one pertaining to royalties.

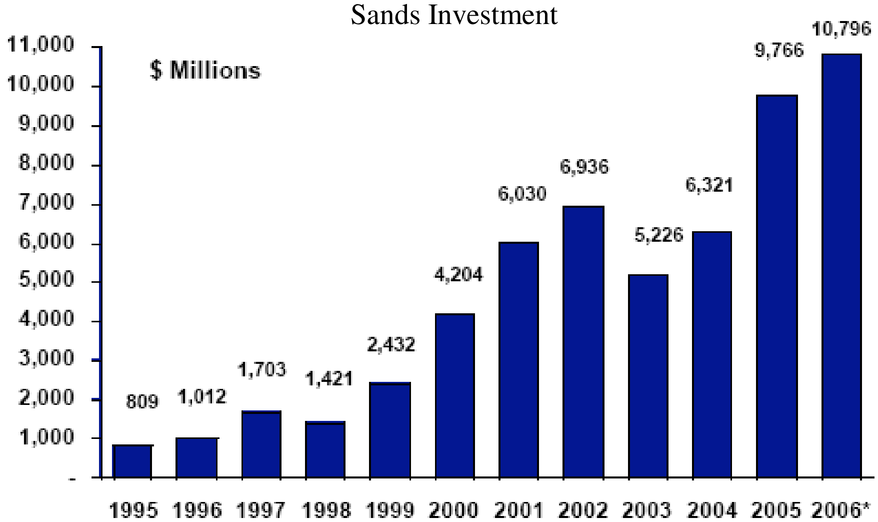
Implemented by the Alberta government in 1997, the new royalty regime (*Oil Sands Royalty Regulation, 1997*), was based upon three main objectives: "accelerating development, facilitating development by private sector companies, and ensuring that development is competitive with other petroleum development opportunities on a world scale"[62] To help achieve these objectives the new regulation stipulated that: "Royalty during the pre-payout stage is 1% of gross revenue; and royalty during post-payout is the greater of 1% gross revenue or 25% net revenue".[63] Put more simply, this new royalty regime meant that on an annual basis oil sand project developers had to give the province a quarter of the net profits of a project, but not before that projected had recovered all

[59] *Ibid*.
[60] *Ibid.* at 3
[61] Taylor, 2007 at 4.
[62] Woynillowicz, 2005 at 61
[63] Alberta Energy, 2008

associated costs**,** *including those related to capital, operating and development, and the project had earned a given investment return.* If a project had not yet covered all these costs then the project owner's royalty for that year was only 1% of the project production.[64]

In addition to this extremely favourable royalty regime, oil sands projects are also blessed with federal tax breaks in the form of a very liberal capital cost allowance rate of 100%.[65] This was implemented via changes to the 1996 Federal Budget when the distinctions between new and existing projects, and surface and in situ projects, were eliminated so that all capital expenditures with a value greater then 5% of project revenues would be eligible for a 100% write-off.[66] The end result of this is that new capital investments or equipment purchases are fully offset against project revenues, thereby lowering the amount of taxable income the project will generate and making oil sand projects more attractive to investors.

Figure 4.3 – Oil Sands Investment



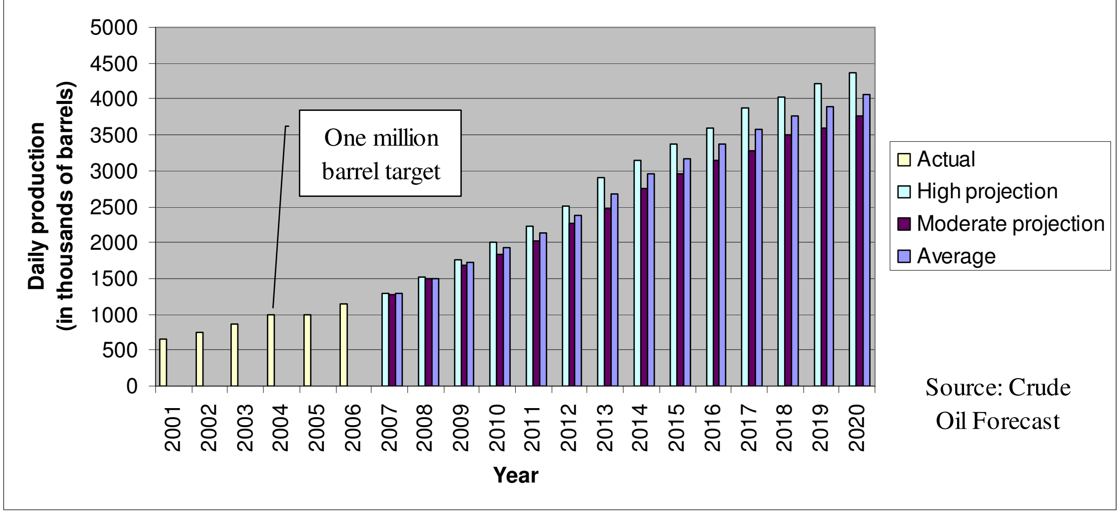
Source: Statistics Canada/Alberta Economic

The motivation behind both these Provincial and Federal actions were clear, to spur investment and development into an oil sands industry that is massively capita intensive, but at the time was not very profitable. Looking back a decade after these recommendations were implemented it would be a vast understatement to say that the task force had been successful in achieving its goals of spurring investment and increasing production. As figure 4.3 clearly shows, despite some fluctuations, annual investment in the oil sands has increased rapidly since 1996, and is now 10 times greater then a mere 10 years ago. With respect to the main overarching goal of increasing production to over a million barrels per day by the year 2020, the next Figure, 4.4 reveals

[64] Taylor, 2007, Models at 2
[65] It has been estimated that the tax benefits accrued to oil sand companies due to this favourable treatment are between $5 and $40 million for every $1 billion invested. In just the seven-year period between 1997 and 2004 these capital investments were thought to be over $27 billion, thus this tax regime has in effect afforded oil sands operations a subsidy in the range of $135 million and $1.1 billion. Woynillowicz, 2005 at 63.
[66] Alberta Energy, 1998

that this was already achieved by 2004, a full sixteen years earlier then hoped for.[67] Also included in Figure 4.4 are the estimated future production figures as forecasted by the Canadian Association of Petroleum Producers (CAPP) in a June of 2007 report.[68]

Figure 4.4 - Projected Oil Sands Production



Within Figure 4.4 potential future production was forecasted under two different scenarios, one where it was assumed that the bulk of currently proposed projects will be both completed on time and achieve their projected capacity, and another scenario which assumed a slower completion rate for the projects, due for example to the severe shortage of labour and input resources that the region is currently experiencing.[69]

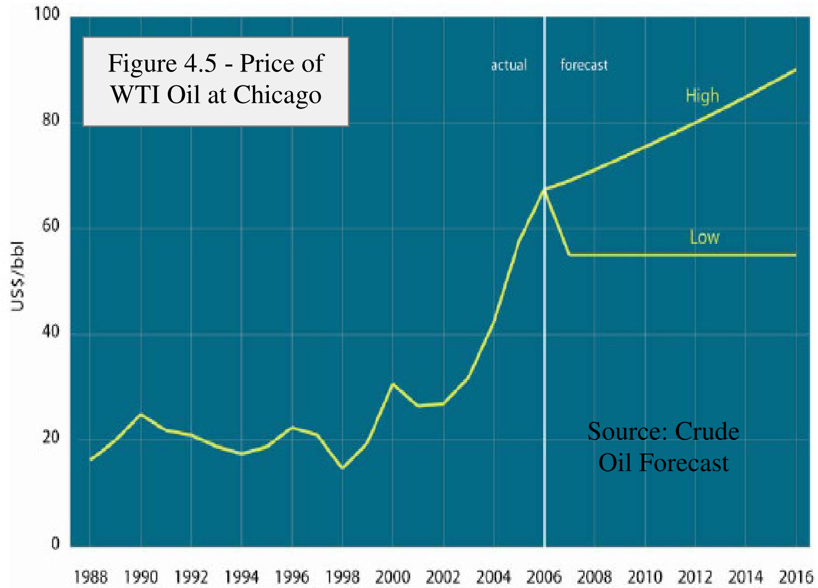
4.5 Oil Prices and Production Costs

In addition to advancements and the fine-tuning of extraction and upgrading technologies that have made the process more efficient and cost-effective, the increase in production has also been urged on by higher than expected crude oil prices. Figure 4.5 on the following page underscores the recent surge in oil prices as it displays the average price of West Texas Intermediate (WTI)[70] at the

[67] Taylor, 2007 at 3
[68] CAPP, 2007 at 3
[69] *Ibid*. at 3-4.
[70] Globally there are a number of different spot prices associated with a barrel of oil, these are referred to as oil benchmarks and the names reflect where that oil originated from as well as its specific characteristics. Benchmarks also have different compositions; those with more sulphur are often referred to as sour, while those with less are sweet, in addition there are also variations in oil viscosity, which leads to oils being classified as either light, intermediate, or heavy. In Europe the benchmark is Brent Crude, in the Middle East the benchmark is Dubai, and the North American benchmark is West Texas Intermediate (WTI). OPEC (The

Chicago exchange dating back to 1988, as well as a range of forecasted future prices for the next nine years.[71]

The profitability of an oil sands project is of course not just determined by the price of oil, but also the cost of producing that oil. In recent years these costs have also increased substantially as the price of steel, cement, equipment, skilled labour, and of particular importance, natural gas, have all increased.[72]



The cost associated with producing a barrel of oil from the oil sands is much higher than that for conventional oil as it is more energy and capital intensive. In Alberta production costs for conventional oil are about $6-10/barrel, while finding and developing costs for new oil vary from $15-20/barrel, which results in a total cost of $20-30 for bringing a barrel of conventional Alberta oil to market.[73]

Alberta oil sands costs vary between facilities and depending on whether the oil is extracted via mining or in situ operations (the two types of extraction methods will be described in more detail later in this chapter). In a 2006 report, the National Energy Board (NEB) estimated the operating cost, and total production cost for both crude bitumen, and crude bitumen that had been upgraded to synthetic crude, using a variety of extraction technologies. A selection of these findings is shown on the following page in Figure 4.6.

Organization of the Petroleum Exporting Countries) also has its own benchmark, a weighted average consisting of the oil from its member countries. Wikipedia, 2008 Petroleum.

[71] EUB, 2007 at 1-6

[72] NEB, 2006 at 3.

[73] Kvisle, 2007

Figure 4.6 - Estimated Operating and Supply Costs

Cost per barrel at the Plant Gate (2005 C$)	**Crude Type**	**Operating Cost[74]**	**Total Supply Cost[75]**
Cyclic Steam Stimulation (CSS)	Bitumen	10 – 14	20 – 24
Steam Assisted Gravity Drainage (SAGD)	Bitumen	10 – 14	18 – 22
Mining + Extraction	Bitumen	9 – 12	18 – 20
Integrated Mining + Extraction + Upgrading	SCO	18 – 22	36 – 40

Source: NEB[76]

Given these figures, the total production cost for a barrel of synthetic crude at the gate of a new integrated mining and upgrading plant is roughly C$36-40, up significantly from the C$26 per barrel cost cited in their 2006 report.[77] The NEB report concluded that given these costs, a WTI price in the range of C$35-41 would be required to provide a 10 percent real rate of return for new and existing mining/upgrading plants.[78] Although the report found that operating costs are slightly higher for in situ operations, the NEB again determined that a WTI price in the range of C$35-41 would be required to earn a minimum 10% real rate of return.[79] As with mining operations, production costs for in situ extraction have also increased dramatically in recent years and therefore NEB also forecasted what effects such increases would have. To maintain the aforementioned 10% rate of return for an integrated mining and upgraded facility it estimated that for every 10% rise in capital costs, the price of WTI would have to increase by approx.C$2.25/barrel.[80] Meanwhile for in situ operations, it estimated that each 10% increase in capital costs would require an increase of C$1.75/barrel.[81]

Referring back to Figure 4.5, we see that the 2006 forecast speculated that the lower boundary for the price of a WTI barrel of oil through 2016 was approximately US$58, while the highest forecasts were in the US$90 range. Given these forecasts and the above mentioned production costs it is easy

[74] The NEB report defined operating costs as those which “reflect the cash costs of operation”. NEB, 2006 at 3
[75] The NEB report stated that supply costs included “all costs associated with production, including operating cost, capital cost, taxes, royalties and a rate of return on investment”. *Ibid.*
[76] *Ibid.*
[77] *Ibid.*, at 5
[78] The actual NEB reported used the figures US$30-35 with an exchange rate of 0.85$US/1C$, however all figures here are in 2005 C$. *Ibid.*
[79] *Ibid.*, at 6
[80] *Ibid.*, at 5
[81] *Ibid.*, at 6

to see why investment into the oil sands has been so rapid and production rates continue to exceed expectations. What is even more astounding is that by the end of 2007 the price of WTI had hit the US$100 mark, thus eclipsing even the highest expectations of the 2006 forecast. The result is that oil sands producers are currently realising tremendous profits and are keen to increase production rates.

4.6 The extraction process, inputs and effects – Surface Extraction

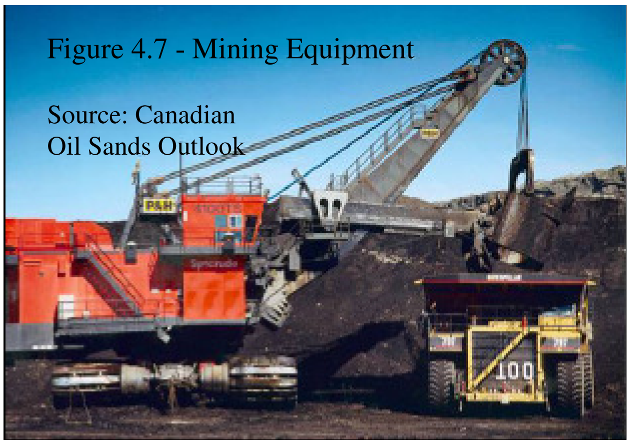


Figure 4.7 - Mining Equipment

Source: Canadian Oil Sands Outlook

In 2006, total oil sands production was 458 million barrels, with 277.6 barrels (over 60%) of the total oil being extracted via surface mining. [82] As of 2006, this brings cumulative oil sands production to 5.4 billion barrels, of which 3.65 billion barrels, or more than two-thirds, has been surface mined.[83] This is due to the fact that surface mining has historically been much less costly per barrel of oil and achieves higher extraction rates, resulting in the recovery of roughly 90% of the bitumen from the deposit. The oil sands are rarely located directly at the surface, but instead below an overburden generally consisting of sand and clay, with muskeg at the very top (a type of bog or wetland). To remove this overburden and extract the actual oil sands (which are generally 40 to 60 meters deep) massive machinery, amongst the largest of its kind in the world, are used.[84] Hydraulic shovels remove 100 tonnes of material with each bucket, loading it into dump trucks that are over fifteen meters long, seven meters high, which then carry their 400 tonne load to a nearby extraction facility. For each barrel of oil produced this involves the removal of roughly two tonnes of overburden, as well as two tonnes of oil sands, and is therefore a very energy intensive endeavour. [85]

Upon arrival at the onsite extraction facility, the oil sands mixture is essentially washed with water to separate the crude bitumen, a process that is also quite energy intensive as the water must first be heated to a very high temperature. Depending on the emissions intensity of the particular plant and

[82] EUB, 2007 at 2-3
[83] EUB, 2007 at 2-3
[84] Wikipedia, 2008 Tar Sands
[85] McCulloch, 2006 at 16

mining site, each barrel of oil recovered via surface mining and extraction it is estimated to release between 28 and 39 kg of CO_2e.[86] Each barrel also requires between two and three and a half barrels (300-550 litres) of water (the amount required is actually much higher, but this figure factors in the recycling of water).[87] However, this is before the crude bitumen has been upgraded into a more readily transportable product. Currently about two-thirds of mined bitumen in Alberta is upgraded on site while the other third is diluted and piped elsewhere for upgrading.

4.7 The extraction process, inputs and effects - In situ Extraction

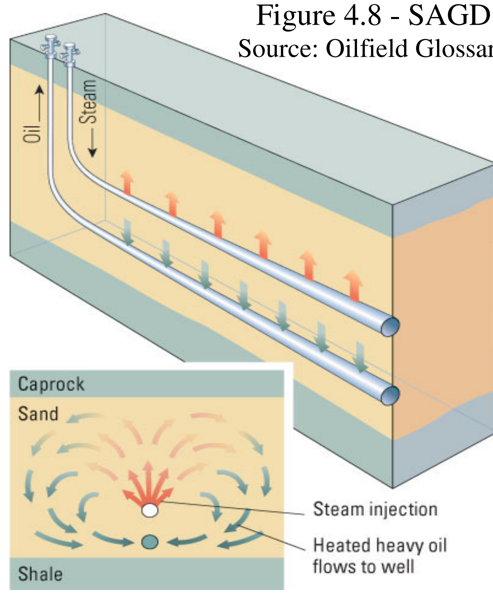
The remaining 180.7 million barrels of 2006 oil sands production (39.4% of total annual production) was produced via in situ extraction, bringing the cumulative in situ total to 1.76 billion barrels, representing less than a third of all oil sands production to date.[88] This has largely been due to the fact that early in situ techniques such as Cyclic Steam Stimulation (CSS) were more costly and had extraction recovery rates of just 20-25%.[89] While CSS is still in use today, and some future projects involving deeper deposits will continue to rely on this technology, the majority of projects will shift to newer technologies such as Steam Assisted Gravity Drainage (SAGD) as it has in situ recovery rates in the range of 60-80%. Within the following five years a number of expansions and new projects using surface mining are scheduled to come on line and as a result it is anticipated that the majority of bitumen (50 - 65%) produced for the next 10-15 years will still come from mining projects.[90] However, the recent advances regarding in situ technology, coupled with the fact that the majority of the oil sands can not be surface mined, means that in the long-term the vast majority of oil sands production will come from in situ projects.[91] More specifically, it is estimated that 141.8 billion barrels (over 82% of the remaining established reserves) are expected to be extracted via in situ methods, as opposed to just 31.5 billion via surface mining.[92]

[86] *Ibid.*, at 14-16
[87] Griffiths, 2006 at 30
[88] EUB, 2007 at 2-3
[89] The early in situ technology, Cyclic Steam Stimulation (CSS), or more commonly, 'huff-and-puff' involved the drilling of vertical wells down through the tar sands. CSS involves three steps: Firstly steam is injected down the wells for a week or more, next there is a week or so of letting the steam heat up the oil, and lastly the warm and less viscous oil is now pumped to the surface for a period of weeks or months. When oil production starts to fall off considerably the process is repeated until it is no longer cost-effective to do so (the major factor being the high cost of steam injection). Deffeyes, 2005 at 103
[90] EUB, 2007 at 2-17
[91] One of the major reasons that the Alberta's oil sands have recently been deemed commercially viable was the invention of SAGD technology. It was due in large part to these advances that Canada's proven oil resources were recently adjusted upwards so dramatically.
[92] EUB, 2007 at 2-2

4.7.1 Steam Assisted Gravity Drainage (SAGD)

SAGD involves the drilling of two horizontal wells, one at the bottom of the oil sands deposit (the producer well), and the other five meters above it (the injector well).[93] While the idea of gravity assisted drainage has been around since the late 1960's, the concept was not proven to be commercially viable till the early 1990's when the Alberta Oil Sands Technology and Research Authority (AOSTRA) ran a successful pilot project in the Athabasca oil sands. Early projects using SAGD had used vertical mineshafts from where the horizontal wells were drilled, however by the mid 1990's directional drilling technology had advanced to the point where this was no longer necessary, thus greatly reducing the cost and time required to drill horizontal wells.[94] High pressure steam is injected via the upper well which heats the bitumen and helps separate it from the sand and clay.[95] The heated crude bitumen is now less viscous so that with the help of gravity it can flow towards the lower producing well where it is pumped to the surface.

Figure 4.8 - SAGD
Source: Oilfield Glossary



In some SAGD projects both wells may be used to initially inject steam. In such cases the heated bitumen between the two pipes flows towards the lower pipe and the area between the two now forms a 'steam chamber'. At this point the projection well stops injecting steam and starts pumping out the bitumen. Meanwhile the injection well continues to inject steam and the steam chamber becomes larger as the steam replaces the extracted bitumen.[96] Each pair of wells is located at a 'well pad' that has been cleared of all surface vegetation and can range in size from one to seven hectares.[97] Pads usually have between four and ten pairs of wells, and the number of well pads for a SAGD project can vary, with larger projects having up to twenty-five.[98] Each well pad receives steam from a central production facility through aboveground pipelines. Via yet another set of

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[93] Woynillowicz, 2005 at 13
[94] Wikipedia, 2008 Steam assisted gravity drainage
[95] McCulloch, 2006 at 16-17
[96] Deutsch, 2005 at 2
[97] Woynillowicz, 2005 at 13
[98] Woynillowicz, 2005 at 13

aboveground pipelines, the extracted water and bitumen mixture is then piped back to the production facility where the bitumen is separated, and the majority of the water is used again. [99]

Compared to the mining of bitumen, SAGD uses much less water as it only requires 30-80 litres per barrel of finished synthetic crude oil (SCO).[100] However it is more expensive, in large part because it requires a great deal of natural gas to heat the steam.[101] This results in a CO_2 intensity that is at least 50% higher for the extraction of bitumen via SAGD, as it releases between 52 and 60 kg of CO_2e per barrel of SCO.[102] With respect to the upgrading of in situ bitumen, the vast majority is currently not upgraded on site, as 2006 saw 91% of in situ crude bitumen exported outside of Alberta in non-upgraded form.[103] However, a number of projects with onsite upgrading are scheduled to come online in the near future so this trend is likely to change.[104]

4.8 Upgrading

Relative to conventional oil, crude bitumen is a viscous complex hydrocarbon, high in carbon and low in hydrogen, and therefore must first be upgraded into synthetic crude before it can be piped to a refinery. Upgrading essentially aims to break these complex hydrocarbon chains into smaller hydrocarbons and remove impurities such as nitrogen and sulphur. The upgrading is done via a combination of the following four processes: Thermal Conversion (coking), Catalytic Conversion, Distillation, and Hydro-treating.

Thermal conversion uses heat to alter the molecular structure of the bitumen, breaking it down into smaller molecules while at the same time removing carbon. When carbon-carbon bonds are broken within these molecules an extra hydrogen atom must be added to each to ensure chemical stability. In Alberta, natural gas is generally used to produce this hydrogen, but if natural gas prices continue their long-term increase this may change in the future.[105] A by-product of this process is coke, which in turn is used in coke furnaces to produce the heat needed for the thermal conversion.[106]

[99] McCulloch, 2006 at 16-17
[100] It should be noted that over time it is estimated that the average water use per barrel of SCO could rise to around 160 litters. This is because the oil that is extracted from the ground will eventually be replaced with another substance, likely water. Griffiths, 2006 at 36.
[101] Griffiths, 2006 at 6
[102] McCulloch, 2006 at 14-16
[103] EUB, 2007 at 2-18
[104] CAPP, 2007 at 4
[105] Deffeyes, 2007 at 102.
[106] Oil Sands Discovery Centre at 1

Catalytic Conversion also uses heat to reduce the molecular size of the bitumen, but a catalyst is added thus enhancing the process and resulting in a higher grade of final product.[107]

Distillation is simply the sorting of the various hydrocarbon compounds found within the crude bitumen. This is accomplished via a distillation tower that is hotter at the bottom and cooler at the top. As a result, the light hydrocarbons with a low boiling point go to the top of the tower as vapour, and the heavier hydrocarbons are collected in liquid form at the bottom.[108]

Lastly there is hydro-treating which once again utilizes hydrogen, as well as heat and catalytic pellets, to remove nitrogen, sulphur and other impurities. The end result is a hydrocarbon compound that is now chemically stable and ready to be blended and sent to the refinery.[109]

Due to the various processes and technologies used by different plants, the amount of SCO produced from crude bitumen can vary. In the major Alberta plants yield rates range from 0.81 to 1.00, with the median and mean both being close to 0.86 (meaning that on average it takes 100 barrels of unrefined crude bitumen to produce 86 barrels of synthetic crude).[110]

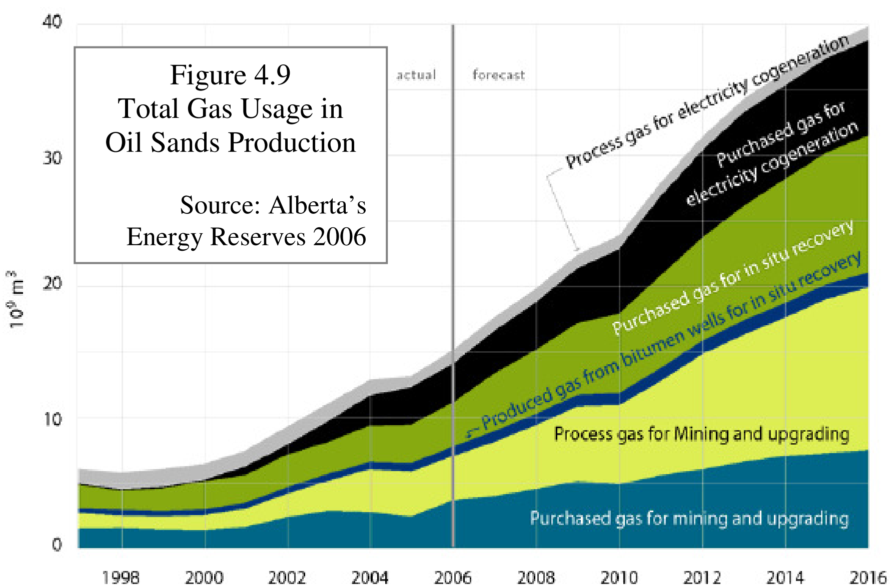

Figure 4.9
Total Gas Usage in
Oil Sands Production

Source: Alberta's
Energy Reserves 2006

4.9 - 2006 Production

Crude bitumen production from mining totalled 278 million barrels (44.1 million m^3), in 2006, while in situ mining produced 180 million barrels (28.7 m^3) for a total of 458 million barrels (72.8 m^3).[111] As noted earlier, the vast majority of the in situ

[107] *Ibid.*, at 2
[108] *Ibid.*
[109] *Ibid.*
[110] EUB, 2007 at 3
[111] *Ibid.*

mined bitumen was not converted to SCO, but the 278 million barrels of mined bitumen was upgraded, and produced 240 million barrels of SCO (a yield of just over 0.86).[112]

To fuel this, oil sands developers purchased 7.1 billion m^3 of natural gas for in situ, mining and upgrading operations. When the other 3.0 billion m^3 of natural gas purchased for electricity co-generation is added, then 2006 purchases of natural gas for oil sands operations totalled more then 10.1 billion m^3. The amount of natural gas *used* by oil sands operators is even greater though, because both upgrading and in situ operations produce gas that is used on site. In 2006 upgrading facilities generated 3.4 billion m^3 of what is referred to as 'process gas', while 0.7 billion m^3 of 'solution' gas was produced via in situ wells.[113] This brought 2006 total gas usage to 14.2 billion cubic meters. Figure 4-9 shows the total gas used from each category since 1998 along with forecasts for the next 10 years.[114] To put the 2006 figures into prospective, this is enough natural gas to heat over five million Canadian homes for an entire year.[115]

4.10 Concern: Natural Gas Usage

One of the major concerns with regard to oil sands development is this tremendous amount of natural gas usage. Natural gas, which is comprised primarily of methane (CH_4) as well as smaller amounts of ethane (C_2H_4), propane (C_3H_8), butane (C_4H_{10}), Carbon Dioxide (CO_2) and other compounds is the cleanest burning of the fossil fuels and is predominantly used in power generation and the heating of homes. The concern with its use in the excavating and processing of oil sands is that while economically prudent (in 2006 a \$65 barrel of oil used between \$4 and \$8 worth of natural gas to be produced[116]), from an environmental standpoint it is a step in the wrong direction. This is because it involves using a low carbon intensive fuel to produce a high carbon intensive fuel. For every unit of energy produced via the combustion of oil instead of natural gas emissions of: Carbon Dioxide are 40% higher, Carbon Monoxide are 21% higher, Nitrogen Oxides are 387% higher, Sulphur Dioxides are 112100% higher, Particulate matter are 1100% higher, and while there is virtually no mercury in natural gas, there is some in oil.[117]

[112] EUB, 2007 at 3
[113] EUB, 2007 at 5-2
[114] EUB, 2007 at 5-3
[115] Based on average sized homes built after 1990 that use approximately 100GJ a year (2680 cubic meters of natural gas). Natural Resources Canada, 2006 at 5
[116] These figures were comprised using: the 2006 average spot price of natural gas (slightly over \$6/GJ), the 2006 average spot price of WTI (roughly \$65), and the range of natural gas used for mining (20 cubic meters) and from in situ (34 cubic meters), and the conversion 1 GJ = 26.8 cubic meters.
[117] NaturalGas.org, 2004

4.11 Concern: Water Usage

In situ demands for water are much lower then that of mining operations and required roughly five million m^3 in 2004, a number that is expected to increase to 13 million m^3 by 2015. [118] The concern with in situ water use is that because these operations are usually not located close to a lake or river the project developers must utilise groundwater. Although much of this water is recycled and used again, a portion of the water is not returned to the cycle as it replaces the oil that has been extracted.[119]

With surface mining projects the excavated crude bitumen sand mixture is in essence washed with hot water to isolate the crude, and therefore mining projects are responsible for the vast majority of annual water usage. Most of this water is drawn from the Athabasca River, where as of 2005 mining projects had licenses allowing them to divert 453 million m^3 (453 billion litres) of water annually.[120] In 2006 the largest city in Alberta was Calgary with a population of just over a million people and it had a per capita water use of 451 litres.[121,122] Thus to put this allocation number into perspective, in 2006 the entire city of Calgary had a water usage of under 168 million m^3, or just over a third of what the mining operations alone were entitled to use. It should be noted that allocated water use and actual water use are not the same thing, as a recent report involving 2004 water use found that of the 180 million m^3 of water allocated to the major mining projects that year, only 55% was used.[123] However, this is not to say that this 55% figure from 2004 is indicative of what water usage percentages will be in the future because recent improvements in the allocation process should result in licenses that better reflect actual usage.[124] In addition, as mining production levels continue to rise significantly over the next fifteen years water demands are likely to grow accordingly. In fact, if future oil sands mining projects are factored in, then the total annual

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[118] NEB, 2006 at 38.
[119] There are a number of potential concerns with extensive water use for in situ operations (issues relating to contamination, drawdown of aquifers, the substantial amount of waste from treated water, and geological alterations due to oil and water removal, etc), unfortunately however they go beyond the scope of this paper. *Troubled Waters, troubling trends* (Griffiths, 2006) is however a great resource on this subject.
[120] Donahue, 2007 at 2.
[121] To be precise: 1,079,310. Statistics Canada, 2008
[122] City of Calgary, 2007
[123] Griffiths, 2006 at 48
[124] This small % of actual usage was largely the result of earlier allocations which did not incorporate the fact that as a project matures less water is needed. Alberta environment has since taking this into account when issuing licensees and new projects now have allocation numbers that decrease according over time. Griffiths, 2006 at 49

withdrawals will be 529 million m^3, a staggering number that could have wide-ranging effects on the entire Athabasca river basin.[125,126]

Reverting back to the city of Calgary comparison, another very significant difference between municipal water use and that from mining operations is that while a great deal of municipal water is diverted back to the river after treatment, the same can not be said for water used in mining operations. Despite the fact that mining operators recycle a great deal of the water withdrawn from the river, less than 10% is ever returned as the vast majority ends in the enormous tailing ponds.[127]

4.12 Concern: Tailings ponds

In the aforementioned process of 'washing' the sand mixture to extract crude there is one rather unwanted by-product. Referred to as 'tailings' and comprised of water, fine sand, silt, fine clay and uncaptured bitumen, this mixture has proven difficult to dispose of. Up to this point these tailings have been sent to 'tailings ponds', massive structures built solely to contain this by-product. The term 'pond' is a bit of a stretch as these 'ponds' are now so large they cover an area of more then 50 square kilometres (enough to cover 56% of municipal Copenhagen) and can easily be seen from outer space.[128] The reason these tailing ponds are so enormous is that for every barrel of extracted crude bitumen there are between three to five barrels of tailings produced.[129] Given daily mining production values of 1.25 million in 2006, this resulted in 3.75-6.25 million barrels of tailings being produced every day.

Figure 4.10 – Tailings Ponds

[125] NEB, 2006 at 38.
[126] There are a number of other water related issues related to mining including the: lowering of groundwater levels, ecological effects on wildlife (particularly fish in the Athabasca River), loss of wetlands, and water quality, however they again go beyond the scope of this paper.
[127] Griffiths, 2006 at 1
[128] Woynillowicz, 2005 at 30
[129] Griffiths, 2006 at 33

Once in these ponds, the tailings mixture settles so that the fine sand and clay form what is referred to as mature fine tailings (MFT) at the bottom, separate from the coarse sand.[130] Recent estimates indicate that this process will take between a few decades, up to a century and a half, depending on the composition of the tailings and technologies employed.[131] In terms of weight, 30% of the MFT are the settled fine particles, while the other 70% is mixed with water that is therefore lost to the process.[132] In addition to this water loss, some of the water takes the place of the excavated bitumen that was located between the grains of sand. The water which is neither trapped in the sand, nor lost to the MFT, rests above the MFT and is dubbed the 'free water inventory'.[133] It is this water on top that can be recycled, although project developers also maintain an approximate three meter deep buffer above the MFT to ensure that wind does not mix the free water with the MFT again.[134]

In addition to concerns of net water loss, the tailing ponds present a number of additional environmental problems. Due to various pollutants within the tailings ponds these ponds have been found to be acutely toxic to aquatic life.[135] Although not deemed acutely toxic to wild mammals (consistent exposure is by no means healthy though), project managers have to employ various techniques to keep birds from landing on the ponds.[136] This is particularly so in spring when many natural ponds are still frozen but the warmer tailing ponds present a welcome stopping point for migrating birds. In addition to the standard floating scarecrow, propane cannons and mechanized peregrine falcon effigies with speakers broadcasting peregrine sounds have been utilised. Even more effective has been linking these cannons and falcon sounds to radar, thus only activating them when birds are approaching so they don't become accustomed to them.[137] Another concern, although unlikely, is that if one of these ponds were to leak there is serious risk of pollutants entering nearby soil, surface water and groundwater, thus resulting in an ecological nightmare that would be incredibly difficult to contain.[138]

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[130] Griffiths, 2006 at 33
[131] *Ibid*
[132] *Ibid*.
[133] *Ibid* at 34
[134] *Ibid* at 34
[135] Of primary concern are naphthenic acids that are common in bitumen, and are also found in area rivers. However, the naturally occurring level is less then 1 milligram per litre, while that in the tailings ponds can be as high as 110 milligrams per litre, a level which is deemed to be acutely toxic to aquatic life. Woynillowicz, 2005 at 31
[136] Woynillowicz, 2005 at 31
[137] Willett, 2006
[138] Woynillowicz, 2005 at 30

4.13 Concern: Affects on Forest and Wildlife

The long-term effects of large-scale oil sands development on the boreal forest in which the oil sands are located are worthy of a lengthy research report in of itself. Included in such a report would be issues related to:

- The complete clearing and dredging of boreal forest and wetlands to make way for massive open pit mining operations.
- The eventual conversion of ecologically valuable wetlands and peat lands (which take thousands of years to create) into reclaimed land consisting of grassy plains or dry forested hilly areas with numerous lakes. These lakes are called end pit lakes as they are the final pit mine from a mining project, and it is at the bottom of these lakes where all the remaining mature fine tailings (MFT) will be placed.[139]
- The even greater amount of forest that is affected via in situ projects due to the numerous well pads (there were over 8500 well pairs in 2006, up from under 4000 just 10 years ago[140]) and vast crisscrossing of pipelines, seismic lines, service roads that completely fragment the landscape.
- The effect of this development and forest fragmentation on wildlife such as the caribou and others whom are very sensitive to changes in their habitat. Such wildlife typically avoid roads, pipelines and other infrastructure, however they will find it very difficult to do so in in situ project areas such as the new Long Lake project where roughly 80% of the total land area is within 250m of one of the above.[141]

4.14 Concern: GHG release

The excavation, processing, and upgrading of crude bitumen is an extremely energy intensive process. For each barrel of synthetic crude oil produced via mining operations approximately 80-100 kg of CO_2e are released into the atmosphere. As outlined earlier, in situ operations require more steam and natural gas and therefore each barrel of SCO results in the release of 104-139 kg of CO_2e. With daily production values currently well over a million barrels a day, it is estimated that total GHG emissions from oil sands plants in 2007 will be in the neighbourhood of 40 million tonnes (40Mt) of CO_2e.[142] Canada's total emissions in 2005 were 747Mt therefore if 2007 emissions were

[139] Griffiths, 2006 at 35
[140] EUB, 2007 at 2-1
[141] Dyer, 2006 at 12.
[142] Dyer, 2007 at 9

similar to this, then the 40Mt coming from the oil sands would represent over 5% of total Canadian emissions.

Figure 4.11 Inputs and outputs per barrel of SCO

Surface mining	In Situ Operations
• 2.2 - 4.4 barrels (350-700 litres) of water [143]	• 0.5 - 1.0 barrels (80-160 litres) of water [144]
• 20m^3 (700 ft^3) of natural gas	• 34 m^3 (1200 ft^3) of natural gas [145]
• Release of 80-100 kg of CO_2e	• Release of 104-139 kg of CO_2e [146]
• 3 - 5 barrels of tailings	

4.15 Potential mitigation possibilities

While all the above concerns regarding oil sands development are severe and must be dealt with, there do appear to be technological advances underway that will at least to a certain extent, mitigate some of them.

With respect to natural gas usage, technologies such as bitumen gasification and the production of synthetic gas in the upgrading step are already being implemented and could greatly reduce the reliance on natural gas in the future.[147,148]

New dry tailings technologies that have recently been implemented in a few projects could greatly reduce the amount of water required for mining, as well as reducing the size of future tailings ponds.[149] Technologies that speed up the settling process in tailings ponds will also reduce water withdrawal as it will allow for quicker recycling of the free water. In terms of in situ projects, new Vapour Extraction (VAPEX) technology could be the answer as it involves injecting solvents such as CO_2 into the ground instead of steam, thus reducing water usage, and as an added bonus it also uses less energy and would store some CO_2 back in ground.[150] Other in situ technologies being

[143] Griffiths, 2006 at 30
[144] As indicated earlier, the number of litters of water needed could rise by over 100 litters per barrel.
[145] NEB, 2007
[146] McCulloch, 2006 at 14-16
[147] EUB, 2007 at 5-3
[148] There has also been a great deal of discussion about the possibility of building a nuclear reactor to generate the steam and electricity required for the oil sands.
[149] Griffiths, 2006 at 118
[150] Griffiths, 2006 at 119

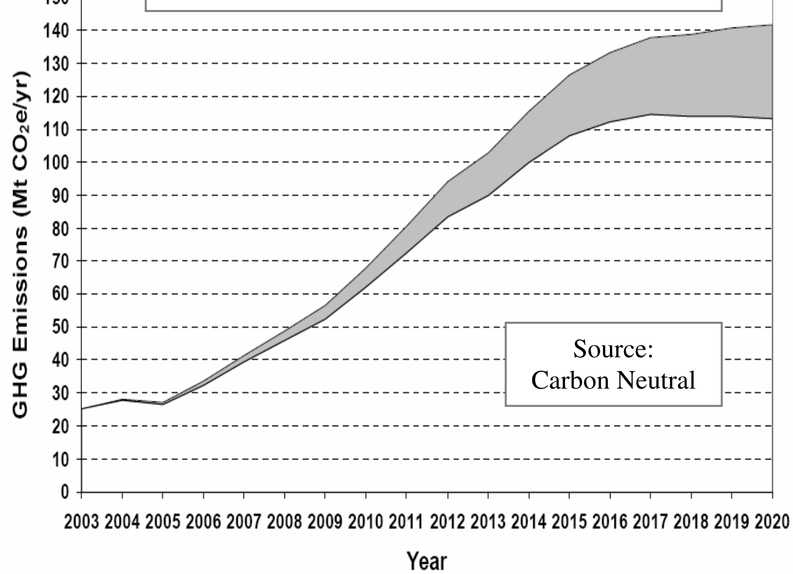
tested that would reduce water use involve: Gasification of the bitumen, heating the bitumen with electric heaters, and heating the bitumen with electro-magnetic stimulation.[151]

4.16 Primary Focus: GHG emissions

Despite the severity of all the issues raised above, the primary concern and focus of the rest of this paper will be on the tremendous amount of GHG emissions associated with oil sands production, and particularly how they can be reduced while at the same time allowing for oil sands development.

One reason for focusing on the emissions concern is that while some of the technological advances listed above may help to slow the *rate of increase* in GHG emissions that are associated with the oil sands, none are likely to result in a net decrease. Another reason for singling out this particular concern is that while still very serious, issues involving water shortages, destruction of forest, and enormous tailings ponds are more localised in nature, mainly affecting Albertans, climate change however is an issue that will affect not just all Canadians, but citizens from the world over, and thus in this respect it bears prioritising. Lastly, and likely the most compelling reason for focusing on the GHG emissions is that at a time when Canada as a nation is trying to reduce its GHG emissions, this largely foreign owned private sector is responsible for the greatest single *increase* nationwide.

Figure 4.12 – Alberta Oil Sands Emissions



If we recall from chapter 3, Canada's annual average Kyoto target for the 2008-2012 period is 563Mt, thus the 40Mt to be released in 2007 represents 7% of Canada's total 563Mt allotment. However, what is alarming is that with all the new projects set to come on line in the next decade, and despite the fact that these new projects are likely to be increasingly energy efficient, total oil sands emissions are going to grow considerably.

[151] Griffiths, 2006 at 120

Figure 4-12 was produced by the Pembina Institute in November of 2005 and shows the range of projected GHG emissions up till 2020 (the grey area represents the upper and lower ranges of the estimation).[152] From this graph we can see that already by 2010, the mid- point of the initial Kyoto period, oil sands emissions will be in the 60-65Mt range, and just two years later they will have increased even more, bringing the 2012 range to 80-90Mt. Therefore, if drastic changes are not made the Alberta oil sands will be responsible for over 15% of the entire country's allotted GHG by the time the first Kyoto period expires, with future annual emissions continuing to increase. As was indicated in Chapter 3, such figures are not compatible with Canadian Kyoto targets and therefore the following chapter will look at one of the most viable options for reducing oil sands GHG emissions, namely Carbon Capture and Sequestration.

4.17 Chapter Summary

This chapter has illustrated the enormity of the oil sands resource which has propelled Canada into the number two spot in terms of global oil reserves. The revenues it is already yielding for oil companies and the public sector alike are enormous and therefore there is little doubt that it will continue to be developed. Unfortunately the nature of the oil dictates that the procurement, processing and upgrading technologies must utilise vast amounts of water and energy, while at the same time releasing staggering amounts of GHGs. As such, new technologies will have to be developed to meet these various challenges. Given both the national and global nature of the climate change threat, the rest of this paper will focus on that issue in particular, and will therefore investigate the potential for CCS to help reduce the GHG emissions associated with oil sands development.

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[152] The assumptions underlying these estimates were: annual production values of 4.2 million barrels by 2015 and 4.8 million by 2020, the main source of energy continues to be natural gas (emissions will be higher if bitumen or coke are used, and lower if nuclear becomes an option), and no use of carbon capture and technology. Bramley, 2005 at 6-7.

Chapter 5 – Carbon Capture and Sequestration

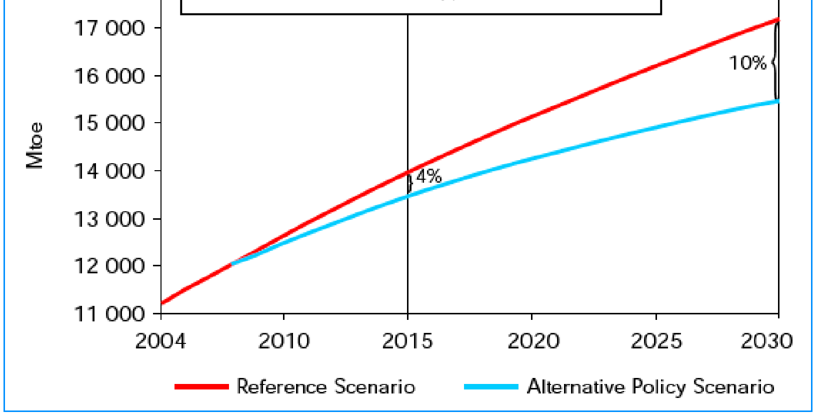
This chapter sets out to explore what Carbon Capture and Sequestration (CCS) entails by first detailing why this relatively new technology is getting so much attention, and then describing the three technologies involved. It then goes on to look at where the various aspects of this technology are currently at in terms of both evolution and cost, and lastly the chapter looks at how well suited Alberta is for the implementation of this technology.

5.1 CCS – A bridging technology?

The term Carbon Capture and Sequestration (CCS) is best described as the fusion of three different technologies whose combined goal is to reduce the amount of CO_2 released into the atmosphere, particularly from large emitting sites. The three steps involve: the capturing of the CO_2 at a large industrial source, the transporting of the CO_2 to a suitable site, and lastly the sequestrating and monitoring of the CO_2 at this site. Unlike CO_2 emission reduction strategies such as the switching to renewables, CCS does not actually reduce the amount of CO_2 produced. However, because the CO_2 is captured and stored in the ground or oceans it greatly reduces the amount of CO_2 that would otherwise be released to the atmosphere, and thus CCS could play a vital role in slowing human induced climate change.

Despite the fact that the majority of scientists now agree that the CO_2 emissions associated with the burning of fossil fuels are likely responsible for accelerated climate change, the reliance on fossil fuels is not going to alter soon. In the popular media we are constantly made aware of new renewable energy projects and their potential; however the stark truth is that the vast majority of our energy is going to come from fossil fuels for many decades. In its *World Energy Outlook 2006,* the International Energy Association provided a picture of what world energy demand will look like in 2030 under two different scenarios. Under the reference scenario, which projects energy demand under a business as usual scenario, it predicted total world energy demand

Figure 5.1 – World Energy Demand
Source: World Energy Outlook 2006



would be over 17 000 Mtoe by 2030, and 81% of this will be provided via fossil fuels.[153] Under the Alternative Policy Scenario, energy demand is projected as if "countries were to adopt all of the policies they are currently considering related to energy security and energy-related CO_2 emissions."[154] These policies include those related to efficiency improvements in energy production and use, as well as renewable energy technologies.[155] Figure 7.1 illustrates these two scenarios. Although total primary energy demand is 1 609 Mtoe less under this scenario, this still represents an annual growth rate of 1.2%, and even more alarming, fossil fuels count for 77% of total primary energy demand.[156] The significance of this statistic can not be overstated; even if we implement all of the policies and strategies to reduce our reliance in fossil fuels currently being considered, by 2030 well over three-quarters of our global energy will still come from the burning of oil, coal, and natural gas. It is precisely for this reason that CCS technology has become so highly discussed in recent years, because it has the potential to prevent the release of a great deal of CO_2 from the burning of fossil fuels in a very short time frame.

Environmental groups were initially very sceptical of CCS (and some still are) because it does not reduce our dependency on fossil fuels and therefore they argue that it diverts resources away from renewable technologies. While not fully disputing this claim, proponents of CCS on the other hand point to the issue highlighted above, namely that renewables will not be able to provide the energy the world requires in the short-term. Thus they argue that CCS should be seen as a type of 'bridging technology', allowing us to continue burning fossil fuels until the renewable energy sector matures and can provide the bulk of our energy requirements. A second issue that opponents of CCS point to is the potential for leakage which could result in local environmental damage, as well as undermine the climate change mitigation efforts. Do to the fact that sequestration technology has not yet been used on a large-scale basis (particularly in geological formations) this is a valid concern. This issue will be dealt with in further detail below, however recent studies indicate that when appropriate steps are taken this risk can be greatly minimised. While not all environmental organisations and watchdogs have embraced CCS, a number of them now support it, with this support usually based on pre-conditions calling for appropriate safeguards, monitoring, verification, and regulatory frameworks being put in place. One such group is the Alberta based Pembina

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[153] IEA, 2006 at 174
[154] IEA, 2006 at 162
[155] *Ibid*.
[156] IEA, 2006 at 173-173

organisation which supports CCS, but with the caveat that the governments' public GHG emission reduction expenditures should first prioritise sustainable initiatives.[157]

As was mentioned above, CCS is basically the combination of three different technological processes. Each of these will be investigated below to determine the current state of the technology, the prices associated with it, as well as any potential concerns. In addition, each section will also look at the relevance of the technology from an oil sands perspective in an effort to determine the feasibility and cost of its implementation.

5.2 Capture Technology

Of the three CCS components, the capture step is by far the most expensive. This is because capturing CO_2 is in itself a highly capital and energy intensive endeavour, and therefore only sites that produce CO_2 in very large amounts qualify as viable options. Such sites include power plants that burn coal or gas, as well as other large industrial applications such as cement production, refineries, iron and steel, petrochemicals and oil and gas processing. While all the previously listed sites produce large amounts of CO_2, they vary in the purity of the CO_2 they release, with most having CO_2 concentrations less then 15%. In fact, according to the IPCC, the overwhelming majority of large CO_2 emitting sources worldwide have CO_2 concentrations less then 15%.[158] Due to prohibitively high prices associated with the transport and sequestration of low purity CO_2, the objective of the capture phase is to isolate CO_2 in a high pressure, high concentration stream that is then ready for transport. The higher the CO_2 concentrations, the cheaper the capture process because this eliminates the need for a separation process. Bearing this in mind, the prime candidates for the implementation of this technology are those which produce a very concentrated CO_2 stream, such as plants that produce natural gas, hydrogen or ammonia, and of particular relevance to this study, this includes some oil sands facilities.[159]

Where fossil fuels are being combusted for energy production, there are three different types of systems via which the CO_2 can be captured: post-combustion, pre-combustion, and oxy-fuel. A diagram outlining theses three, as well as industrial processes, is shown on the following page in Figure 5.2.

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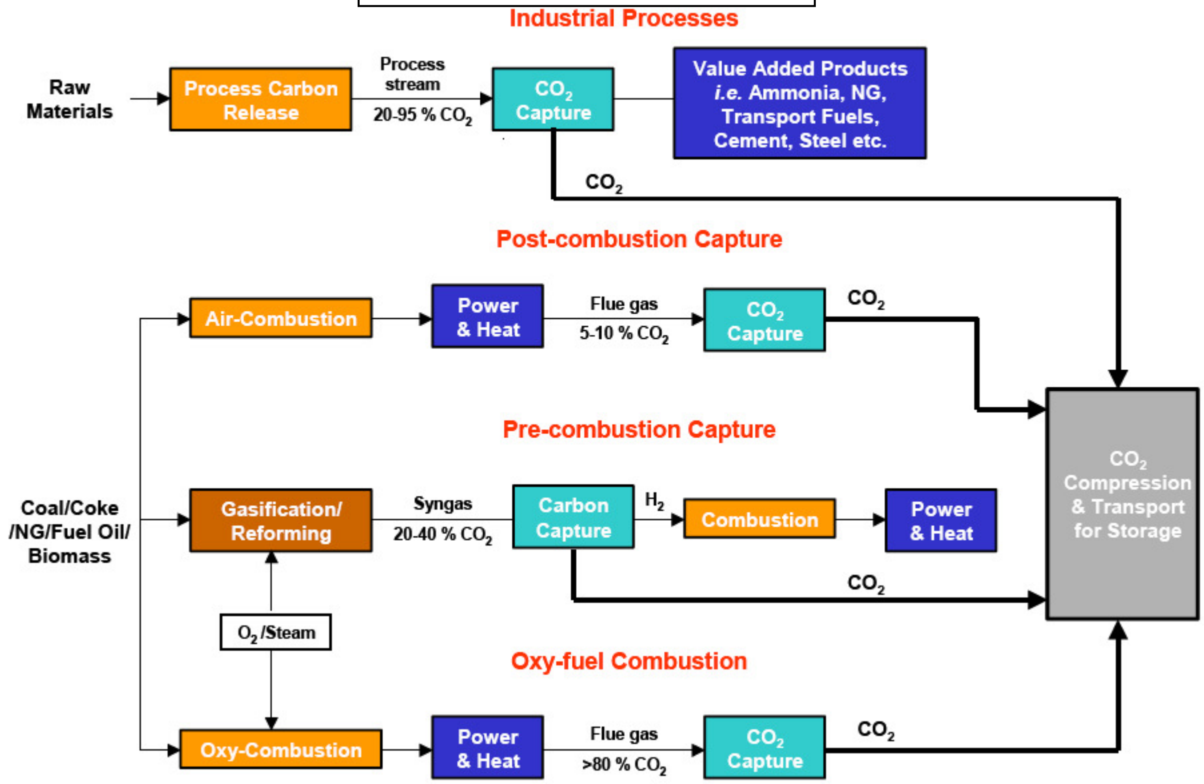
[157] Bramley & Griffiths, 2005 at 2
[158] IPCC, 2005 at 19
[159] Natural Resources Canada & CETC, 2006 at 38

Figure 5.2 - CO_2 Capture Processes
Source: CANiCAP



5.2.1 Post-combustion Capture

As the name would indicate, post-combustion capture involves the capture of CO_2 after the fossil fuel has been combusted. This is done by installing a system which scrubs the CO_2 out of the flue gas.[160] The advantages of post-combustion include the fact that it is the most mature of the three combustion technologies, and that it can be fitted on to existing plants.[161] On the other hand, flue gas emanating from post-combustion systems is usually under low pressure and has very low concentrations of CO_2 (ranging from 5-15% CO_2).[162] Because it requires more energy to capture CO_2 streams that are low in concentration and pressure, relative to pre-combustion and oxy-fuel systems, post-combustion systems are more costly and energy intensive.[163] In addition, the technology most often used for scrubbing CO_2 in post-combustion processes involves the use of an amine solvent which produces a toxic amine waste; thus if large scale CCS was to be undertaken

[160] Alberta Research Council Inc., 2005 at 15
[161] Carbon Neural, page 22.
[162] Alberta Research Council Inc., 2005 at 15
[163] *Ibid*.

with this technology very large amounts of this waste would be produced.[164] While advances in scrubbing technologies are expected to take place, at this point it appears that post-combustion is not the best option due to the high energy requirements and large amounts of toxic amine waste that would be produced.[165]

5.2.2 Pre-Combustion Capture

In pre-combustion systems the initial fuel is first converted to a synfuel (also know as syngas), a mixture consisting mainly of carbon monoxide (CO) and hydrogen (H_2).[166] When the primary objective is to produce hydrogen from natural gas, Steam Methane Reforming (SMR) is the most common process for producing the synfuel; however this first step can also be achieved by gasification or partial oxidation using biomass or other fossil fuels as the input.[167,168] Once the synfuel has been created, the next step is a water-gas shift which converts the CO and H_2 synfuel, to CO_2 and additional H_2. At this point the H_2 is separated for use, and the CO_2 can be captured.[169] For fossil fuel combustion, pre-combustion capture systems receive a CO_2 stream under a much higher pressure and temperature than post-combustion systems, and CO_2 concentration percentages are also higher.[170] Because the CO_2 is under a higher pressure it is possible to use different scrubbing techniques (physical solvents for example) which don't result in the unwanted toxic amines produced via post-combustion scrubbing methods. In addition, the higher concentration, temperature, and pressure also make capture less costly as it reduces the amount of steam required, and therefore compression and energy related costs are lowered.[171]

Presently there are a small number of different pre-combustion systems in place, including integrated gasification combined cycle (IGCC) and integrated gasification hybrid cycle (IGHC). While neither of the two commercial-size IGCC plants in the United States have been outfitted with capture technology to date, it would be possible to do so in the future. More relevant is the fact that although these plants received government support in the past, both are now producing electricity

[164] Cobb, 2005 at 23
[165] Cobb, 2005 at 23
[166] Cobb, 2005 at 24
[167] SMR requires high temperatures and a metal catalyst, while gasification generally utilises oxygen as an input.
[168] Alberta Research Council Inc., 2005 at 16.
[169] Cobb, 2005 at 24
[170] Alberta Research Council Inc., 2005 at 16.
[171] *Ibid*.

without any financial aid.[172] This is important because it demonstrates that IGCC plants of this size are close to competing with conventional coal plants, and thus pre-combustion technology is ready to be incorporated with CCS.[173]

5.2.3 Oxy-Fuel Combustion Capture Systems

In a regular combustion system the source fuel is combusted with atmospheric air, which has a molecular makeup of roughly: 78% nitrogen, 21% oxygen, and 1% argon. The resulting flue gas from this combustion is composed of N_2, NO_x, and CO_2.[174] In an oxy-fuel system however, the combustion occurs in a pure oxygen environment and as a result the flue gas is essentially water vapour and CO_2. Relative to post-combustion methods the flue gas therefore has a much higher concentration of CO_2 and this makes capture easier and less costly. The high CO_2 concentration also allows for the use of physical capture processes which have much less waste then their moist solvent counterparts.[175] In addition, because the nitrogen is never combusted, oxy-fuel capture systems have the added bonus that they greatly reduce harmful NO_x emissions.[176] Oxy-fuel systems are not without their drawbacks as well though. Firstly, the process by which the input oxygen is produced is quite energy intensive. Also of particular note is the fact that combustion in pure oxygen results in extremely high combustion temperatures that regular metals and turbines can not tolerate, and therefore additional steps must be taken to keep the temperature at appropriate levels.[177]

5.2.4 Cost estimates for combustion technologies

A recently released MIT study looked at the three different types of coal fired combustion plants in an attempt to determine what the incremental price of electricity would be for each plant type if CCS were implemented. As a reference point the study used a 500 MW Supercritical Pulverized Coal Unit without capture ability and compared this to four 500 MW plants: an IGCC Unit *without* CO_2 capture, a Supercritical Pulverized Coal Unit *with* CO_2 capture, an IGCC Unit *with* CO_2

[172] Clean-Energy.us, 2006
[173] A recent MIT study found that the price of electricity from an IGCC plant was only 5% higher then that from a similar 500 MW Supercritical Pulverized Coal plant. This slightly higher price is compensated by much lower NOx, mercury and SO_2 emissions from the IGCC plants. MIT, 2007 at 36.
[174] Cobb, 2005 at 27
[175] *Ibid*.
[176] *Ibid.*
[177] *Ibid.*

capture, and a Supercritical Oxy-Fuel Unit *with* CO_2 capture.[178] Each plant was designed to remove over 90% of the CO_2 and have CO_2 streams with similarly high concentrations (over 90%) and pressure (150 atm) so that CO_2 is ready for transport and sequestration. Some results from their study are shown below in Figure 5.3.[179]

Figure 5.3 - Cost of Capture for Coal Fired Power Plants

Type of Capture Plant	Cost of electricity (¢/kWe-h)	Cost relative to ref. plant (¢/kWe-h)	Cost relative to ref. plant (%)	Cost per ton of CO_2 avoided (2005 $US)
Post-Combustion **w/o** capture (ref.)	4.78	0	0	N/A
Pre-Combustion IGCC **w/o** capture	5.13	0.35	7.3%	N/A
Post-Combustion SCPC **w/** capture	7.69	2.91	60.9%	40.4
Oxy-Combustion SCPC **w/** capture	6.98	2.20	46.0%	30.3
Pre-Combustion IGCC **w/** capture	6.52	1.74	36.4%	24.0

Source: The Future of Coal

As can be seen from the chart, without capture, the cheapest electricity is produced by conventional post-combustion plants; nonetheless current IGCC plants are not far behind with production prices only 7% higher. However when we add the cost of capture, post-combustion quickly becomes the most expensive, followed by oxy-fuel combustion, while IGCC capture plants produce the cheapest electricity. In terms of the CO_2 abatement costs, post-combustion capture plants would cost over US$40 per tonne, while oxy-fuel around US$30, and IGCC plants US$24. For post-combustion plants a large portion of the capture cost is due to the necessity of using amines, a process that requires a great deal of energy. In addition, the low pressure CO_2 stream must be increased, again resulting in energy losses. For oxy-fuel systems the concentration of the CO_2 stream must also be increased, however the MIT study postulates that if the CO_2 purity restraint could be loosened, then current oxy-fuel capture systems could likely produce electricity at 1.8 ¢/kWe-h, very close to the current cost of IGCC capture plants 1.74 ¢/kWe-h.[180]

[178] There was no comparison made with an Oxy-Combustion w/o capture as there exists little incentive to build an oxy-fuel plant without a capture system.
[179] It should be noted that only the price of capture is factored into this graph, the prices associated with transport and sequestration will be dealt with later in the chapter.
[180] MIT, 2007 at 31.

5.2.5 Retrofitting of existing plants

Figure 5.3 was based on costs associated with building new plants that had capture technology integrated from their inception. Given the large number of exiting power plants, and their long operational lifespan, it is also worthwhile to look at the possibility of retrofitting these plants with capture technology. With respect to the possibility of retrofitting existing post-combustion plants, the MIT study found that in most circumstances this would unlikely to prove cost-effective due to electricity reduction rates of roughly 40% in such plants.[181] However, the study did conclude that instead of simply retrofitting a plant with a capture system, a more viable option would be rebuilding the core of the plant in conjunction with adding a capture unit. Although this involves a higher initial cost, this capital cost would be compensated by the overall efficiency gains due to boilers and turbines that would then be in the proper proportions. Such rebuilds would be particularly cost-effective when sub critical units were replaced with more efficient post-combustion units (supercritical or ultra-supercritical), or oxy-fuel units.[182]

The MIT study found that retrofitting a pre-combustion plant would be less costly than a post-combustion plants retrofit, and therefore a viable option. However, it should be noted that a retrofitted IGCC plant would not be as efficient as an IGCC plant that was initially built with capture capability. In general the study indicated that while leaving additional space for future retrofits would be advisable when building non-capture IGCC plants, investments geared to making the plant easier to retrofit in the future were deemed "unattractive".[183]

5.2.6 Summary of combustion capture technologies

Price wise, current IGCC non-capture plants are nearly competitive with post-combustion plants but likely require some initial government assistance. As IGCC plants involve a much newer technology their potential for technological improvements is higher and therefore this price gap is likely to be reduced even further. In addition, as emission constraints (mercury, NO_x, etc) become more stringent it is less costly to meet these demands with IGCC and oxy-fuel plants then that of post-combustion plants. Lastly, it is only a matter of time before CO_2 emission constraints come into effect, at which time IGCC plants will become much more cost-effective than conventional

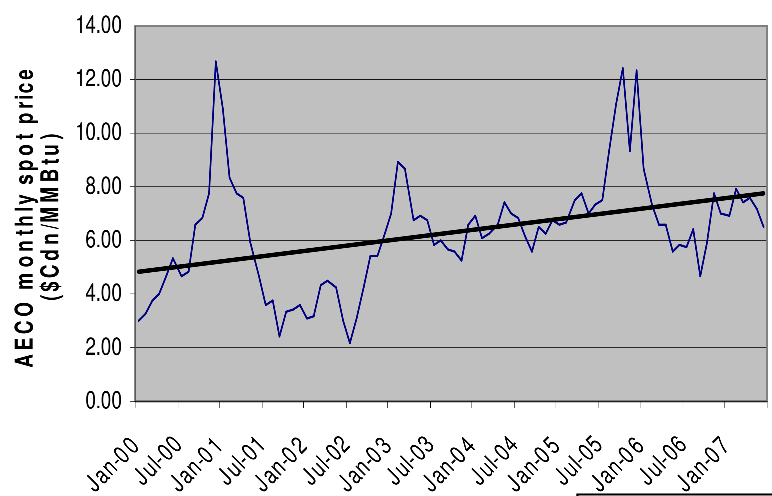
[181] These large reductions in electricity output are due to the substantial amounts of steam required in the amine absorption process. As a result the plant as a whole operates less optimally, as the original boiler still runs at original capacity, but the steam turbines are only running at 60%. MIT, 2007 at 28.
[182] MIT, 2007 at 29 and 32.
[183] MIT, 2007 at 38

post-combustion plants. Current oxy-fuel plants are not competitive with post-combustion plants, however if advancements in capture methods allow for a lower pressure CO_2 steam to be used, then oxy-fuel capture plants will not only be cheaper then post-combustion capture plants, but may become competitive with IGCC capture plants as well.

5.2.7 Relevance of combustion capture technologies for Oil Sands

The relevance of combustion capture technologies for the oil sands is two fold, with the first reason having to do with how onsite electricity is likely to be produced in the future. Currently the majority of electricity (in the neighbourhood of 80%) used by oil sands facilities is produced via onsite cogeneration plants.[184] These cogeneration plants are also known as combined heat and power (CHP) facilities because in addition to producing electricity, they also produce the large amounts of steam that oil sands production and upgrading requires. These CHP plants are relied upon because they provide a reliable source of steam and power, and their dual purpose makes them very efficient from both an environmental and economic perspective.[185] However, these plants are predominantly fuelled by natural gas, which in recent years has seen more volatile prices and an overall upward trend. Figure 5.4 details the AECO "C" spot price of natural gas each month from Jan of 2000, till June of 2007.[186] Concerns with natural gas price increases and volatility have resulted in oil sands operators looking at alternative fuels for producing their required steam and energy, in particular the use of coal, bitumen, or petroleum coke

Figure 5.4 – Alberta Natural Gas Prices



Source: Sproule

[184] NEB, 2007 at 45
[185] *Ibid.*
[186] The AECO price is the Alberta gas trading price.

in syngas operations.[187] Such operations would utilise pre-combustion technologies such as IGCC and are therefore prime candidates for the implementation of CCS technology.

The second major reason that combustion capture technology is relevant to the oil sands is that for CCS to prove cost-effective it must be undertaken on a large scale, incorporating major CO_2 emitting sites from all over the province via a network of CO_2 pipelines and sequestration sites. If oil sands operators are aware that combustion capture technology (for example IGCC coal fired power plants) is soon to be applied province-wide, then there will be a greater incentive for oil sands operators to plan for and implement CCS technology into present and future plants.

5.2.8 Industrial Processes

While the previous section outlined the importance and potential of combustion capture technologies in the oil sands, an area that may have even greater applicability for the oil sands is that of industrial processes. Examples of industrial processes that vent large amounts of CO_2 into the atmosphere include ammonia production, cement and steel manufacturing, fertilizer production, ethanol and ethylene oxide plants, and of particular relevance to this study, natural gas processing and hydrogen production.[188]

Alberta is a large producer of natural gas, and as natural gas has some CO_2 that must first be separated before it can be processed, this CO_2 is generally just released into the atmosphere.[189] Currently Canada emits about 9 Mt of CO_2 per year from the production of raw natural gas that on average contains a CO_2 concentration of 2.4%.[190] However, the raw natural gas to be recovered in the future is estimated to have a CO_2 concentration of 3.5%, which combined with expected increases in Western Canadian natural gas production levels as high as 50%, could see the annual release of CO_2 from natural gas production rise to 20 Mt.[191] Given that this is a relatively pure stream of CO_2, natural gas processing represents a prime candidate for CO_2 capture.

As was detailed in Chapter 4, hydrogen is used within the oil sands industry to upgrade crude bitumen into synthetic crude oil, and while hydrogen is also used to upgrade other petroleum products, oil sands bitumen requires up to ten times as much hydrogen as these conventional

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[187] NEB, 2007 at 46
[188] Alberta Research Council Inc., 2005 at 16.
[189] Cobb, 2005 at 33
[190] *Ibid*.
[191] *Ibid.*

products.[192] This hydrogen is predominantly produced with natural gas as the input, and one of the main by-products being a concentrated stream of CO_2 that could easily be captured. Within the next ten years the demand for hydrogen from the oil sands is expected to more then quadruple, resulting in an annual CO_2 emissions of 13 Mt.[193]

In addition to the MIT study mentioned above, another paper that looked at the potential price of implementing capture technology was one by the Pembina Institute. It found very similar costs with respect to IGCC and oxy-fuel capture units in electricity production. In addition, it also looked at the potential costs of carbon capture from non-combustion sources used in the oil sands and found that natural gas processing and hydrogen production had capture cost estimates ranging from US$13 to US$20 per tonne.[194] Relative to the capture costs from combustion facilities, these much lower prices are due to the higher pressure and concentration of the CO_2 stream produced, and therefore they represent some of the best options for carbon capture.

Thus if CCS technologies were implemented soon, a number of existing facilities would be good sources of high purity CO_2 (and therefore have relative low capture costs). In addition, if oil sands operators are aware that CCS options will exist in the near future, then new projects will continue to use these low cost capture technologies instead of switching to alternative technologies. These alternative technologies are being considered because they result in efficiency gains, however they make CO_2 capture more difficult and costly and therefore it is important to establish CCS networks as soon as possible.[195]

5.3 Transport Technology

Once the CO_2 has been captured, the next step is transporting it to an appropriate area for storage. While CO_2 can be transported overland by tanker (rail or truck), the most cost-effective method for large-scale transport is via pipelines. Of the three main CCS components, transport technology is the most mature as CO_2 pipelines have been in commercial use since the 1970's. A number of these pipelines operate in the United States, as well as one that originates in North Dakota and transports CO_2 to an enhanced oil recovery project in Saskatchewan, Canada.[196]

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[192] Cobb, 2005 at 33
[193] *Ibid.*
[194] *Ibid.* at 30
[195] Cobb, 2005 at 25-26
[196] Natural Resources Canada & CETC, 2006 at 50

One concern associated with CO_2 pipelines is that of leaks, particularly in low-lying areas because CO_2 is both odourless and heavier than air, and would therefore not disperse or be readily noticed without proper monitoring equipment.[197] With respect to other substances that are transported by pipeline, the risk of a CO_2 leakage may be slightly higher because of its corrosive nature. However, this risk can be mitigated by implementing advanced capture systems which produce a CO_2 stream free of hydrates and corrosive materials.[198] On the other hand, unlike other pipelined products, CO_2 is neither flammable nor explosive, so in this sense it is much safer to transport.[199]

The cost of transporting CO_2 via pipelines is dependent on a number of factors, including the terrain through which the pipeline will cross, the diameter of the pipeline, the length of the pipeline, and whether the CO_2 is piped in its gaseous or liquid phase.[200] While pipeline costs can vary, Figure 5.5 reveals that the transport stage of CCS is much less costly than the capture stage. As can be seen from the diagram, transport costs are highly dependant on the capacity of the CO_2 pipeline, with flow rates of 10Mt/yr and greater being the most efficient. With 2007 emissions from oil sands operations likely to be over 40Mt, and future emissions only expected to increase, the transport cost is likely to fall in the range of US\$0.50 - US\$1.50/t CO_2 for each 100 km. In Alberta the most suitable storage sites are approximately 500-700km away from the oil sands and therefore would result in total transport costs in the neighbourhood of US\$3.00-\$7.00. These figures are again similar to those found by the aforementioned Pembina report which estimated the cost of a 650km pipeline network from the Fort McMurray area to Drayton Valley with a capacity of 14.5Mt CO_2/yr to be US\$7.00/tonne.[201] It should be noted that the MIT report is more recent and

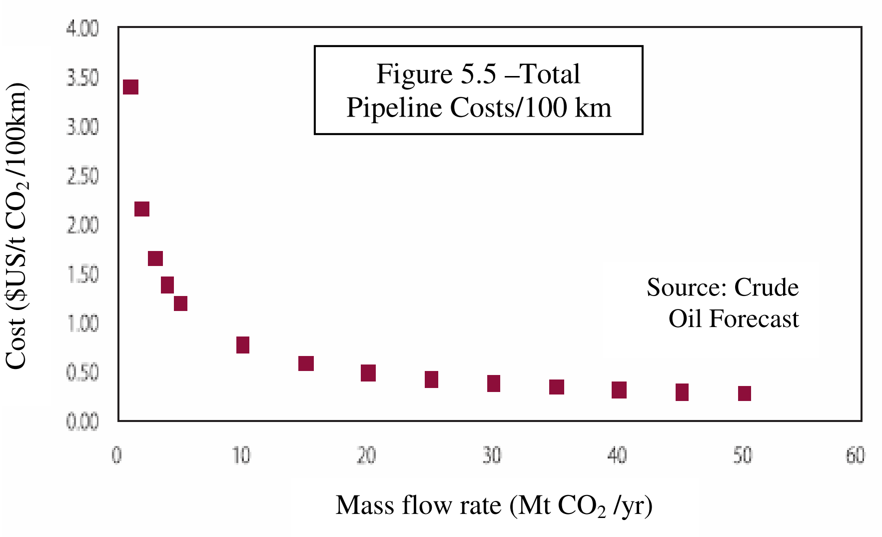


Figure 5.5 –Total Pipeline Costs/100 km

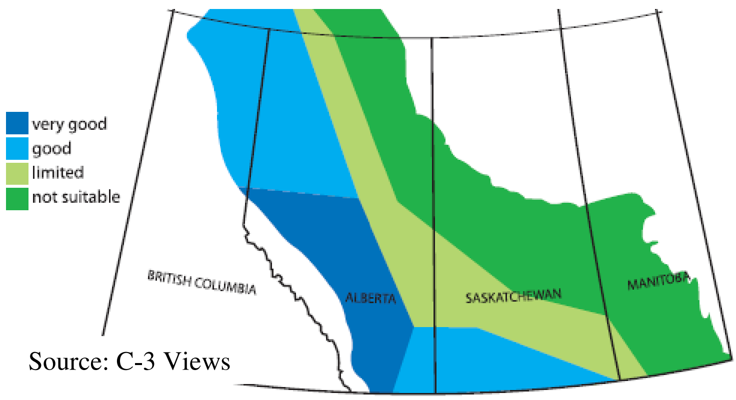
[197] Cobb, 2005 at 34
[198] Natural Resources Canada & CETC, 2006 at 50
[199] *Ibid*.
[200] It is generally lost costly to transport CO_2 as a dense liquid, however this also requires more energy. McCulloch, 2006 at 25
[201] McCulloch, 2006 at 25

comprehensive, while the Pembina report is more site specific. However as the Pembina report looked at a network with a capacity of only 14.5Mt, a larger network could reduce the per tonne cost to lower then the estimated US$7.00/tonne.

5.4 Sequestration and monitoring technology

The last stage of CCS is the sequestration and monitoring stage where the CO_2 is pumped into the ground for permanent storage and monitored to ensure it does not migrate back up to the surface. While it may be the last stage, it is often looked at first because without suitable nearby storage locations for the CO_2, the transportation costs soon escalate. Luckily for Western Canada this is not an issue as there exist vast storage opportunities throughout the Western Canadian Sedimen-ntary Basin (WCSB), an area consisting of Alberta, Saskatch-ewan and parts of Manitoba and British Columbia. While exact figures are not available, the potential storage capacity within the WCSB is thought to be in the neighbourhood of 1 000 gigatonnes (Gt). To put this number into perspective, recall that Canada's total GHG emissions in 2005 were 747 Mt CO_2e, thus at 2005 emission rates the WCSB alone would have enough storage capacity for Canada's emissions up till the year 4014. Figure 5.6 gives an idea of the area encompassed by the WCSB and indicates which areas are best suited for sequestration. There are a number of different storage options within the WCSB (Alberta having many of the best potential sites) with costs varying between these options, particularly between the 'value added' and 'non value added' sites.

Figure 5.6 – Prospective CO_2 Sequestration Sites



Source: C-3 Views

5.4.1 Value Added Storage

'Value added' refers to CO_2 storage options that have a negative cost; that is sites where the injection of CO_2 results in an economic payout. This typically occurs because the injection of CO_2 leads to higher recovery rates of fossil fuels such as oil and natural gas. The injection of CO_2 into an oil well to increase recovery rates is referred to as Enhanced Oil Recovery (EOR) and it increases yields for two reasons. Firstly, when the CO_2 is injected into the oil it mixes and dissolves in the oil, thereby reducing its viscosity and making it easier to extract. Secondly, the injecting of CO_2 also increases the pressure within the reservoir which again results in more oil being recovered. All told, at appropriate sites CO_2 EOR can boost oil extraction rates by an average of 50% of the recoverable reserves (this average is the result of an expected 8-15% extraction increase of the total resources in place).[202] Currently these processes result in roughly half of the CO_2 remaining in the ground, with the other half coming back to the surface where it is captured and reused. With the objective now being to trap as much CO_2 in the ground as possible (whereas before the focus was on increased oil production, thus CO_2 coming back up was seen as a positive) it is likely that adjustments to the technology will result in more then 50% of the injected CO_2 being trapped permanently on the first injection.[203] Within the WCSB there exist a number of opportunities for EOR, with total potential capacity at these sites estimated to be 639Mt. This technology is relatively mature as there are already EOR projects within the WCSB that as of 2004 were storing more than 2Mt of CO_2 a year. The most prominent of these is a project located in Weyburn Saskatchewan which will be further investigated in proceeding chapters.

Although not as economically attractive as its oil counterpart, another possible value added storage opportunity is Enhanced Natural Gas Recovery (ENGR). It is thought that because CO_2 is denser than natural gas, if pumped into a reservoir CO_2 could improve both recovery rates and times. The Alberta Research Council has high hopes for this technology and is testing the technology in its labs; however working examples of this technology have not yet been undertaken.[204] While there exist a number of natural gas deposits in the WCSB where ENGR could likely be used to extract the remaining natural gas (as well as a number of old oil reservoirs where past EOR techniques pumped natural gas into the wells), at this point they would not be cost-effective to exploit because the CO_2 is currently too expensive, and current natural gas recovery rates are already much higher then conventional oil rates as they average about 90%.[205] If natural gas prices continue to increase and/or some type of carbon tax is introduced, then ENGR projects will become more appealing, but most will not be undertaken until the more profitable EOR capacity has been utilised.

Enhanced Coalbed methane (ECBM) is another area that could see extraction rates rise from current 40-50% levels to 90-100% with the injection of CO_2. However this technology is still very much in

[202] Natural Resources Canada & CETC, 2006 at 53
[203] *Ibid*.
[204] Alberta Research Council, 2007
[205] Natural Resources Canada & CETC, 2006 at 54

its infancy and more research will have to be done to solve a number of the economic and environmental question marks surrounding this technology.[206]

5.4.2 Non-Value Added Storage

Until there is a significant price put on CO_2 emissions, non-value added storage options are unlikely to be used as the value-added options will of course be exercised first.[207] However, a significant change in current Canadian climate change policy and a resulting high price on CO_2 emissions could make many of these options cost-effective. In addition, if a comprehensive CO_2 network is to be established for large-scale and long-term sequestration, then non-value added sites will have to be incorporated as well.

5.4.2.1 Depleted Oil and Gas Reservoirs

Abandoned oil and gas fields are prime locations for injecting CO_2 as the pore space that was once occupied by oil or gas can now be filled with the CO_2. It is worth noting that although a pool may be considered depleted or abandoned, it can produce once again if the reservoir alters physically, and/or fossil fuel prices increase to a level where the reservoir is once again profitable. Relative to other non-valued added options, depleted oil and gas reservoirs are favourable because geologists are familiar with the sites and they have already proven that they can contain oil or gas for millions of years.[208] Gas reservoirs are preferable to oil reservoirs because they are larger and more plentiful, and there are a large number of both within the WCSB.[209] Storage capacity within gas reservoirs in the WCSB are estimated to be 8557Mt, with oil reservoirs providing another 853Mt.[210,211]

Storage sites with a capacity greater than 1 Mt are more cost-effective, as are those with depths between 900 – 3500m because it is at these depths below 800m that the pressure and temperature will result in the CO_2 taking its desired liquid or supercritical state.[212] Sites that meet both these

[206] Natural Resources Canada & CETC, 2006 at 54
[207] It is possible that CO_2 emissions from some of the sources listed above will be too impure to be used in EOR and the resulting costs associated with making them acceptable for EOR might actually make non-value-added storage more cost-effective.
[208] Natural Resources Canada & CETC, 2006 at 55
[209] Natural Resources Canada & CETC, 2006 at 56
[210] Natural Resources Canada & CETC, 2006 at 37
[211] This estimate may be on the low end, as other published reports indicate that total depleted oil and gas reservoir capacity is approximately 15,000 - 20,000 Mt of CO_2.. McCulloch, 2006 at 25
[212] IPCC, 2005 at 18

criteria within the WCSB have a combined storage capacity of 3200Mt in gas reservoirs, and 562Mt in oil reservoirs, with Alberta alone counting for 2822Mt of this more attractive capacity.[213]

5.4.2.2 Deep Saline Aquifers

The largest potential for worldwide storage is in deep saline aquifers which are plentiful throughout the world and are situated under much of Alberta where they have an estimated capacity close to 1000 Gt. With saline aquifers the CO_2 is pumped deep underground into a layer of porous rock that is saturated with brine. The brine and CO_2 will both move to the surface as they flow through the porous rock, however the water is attracted to the rock surface and therefore will cling to the pores which will eventually restrict the flow of CO_2, thus trapping it within the pores.[214] While not yet a mature technology, a recent study indicates that the CO_2 can be safely stored in these tiny pores for centuries. The CO_2 will eventually dissolve in the brine, and a small portion of the CO_2 will actually react with the rock to produce minerals such as iron and magnesium carbonates.[215] These findings verify earlier postulations made by the IPCC which indicated that CO_2 could be trapped in such aquifers for millions of years, with the sites having retention rates of over 99% over 1000 years.

5.4.3 Costs of Sequestration and Monitoring

For value added storage there is a negative cost associated with the sequestering of CO_2, while non-value added sequestration costs in Canada will likely range from C$3 to C$9 per tonne.[216] Depleted oil and gas reservoirs will be at the lower end of this cost spectrum while geological injection costs will depend on the particular formation, the depth that must be drilled, and the capacity of the reservoir.

Once the CO_2 has been sequestered it is important that it is monitored to both ensure that there are no major leaks, and also so that the total amount sequestered can be verified on an ongoing basis. While a small amount of seepage is expected to occur, it is important that this is kept to a minimum to both reduce the prospect of local environmental damage, as well as keep the CO_2 from reaching the atmosphere and thus undermining the climate change efforts of the sequestration. In this regard, it has been estimated that seepage rates of less then 0.1% would be deemed acceptable.[217]

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[213] Natural Resources Canada & CETC, 2006 at 37
[214] Green Car Congress, 2007
[215] *Ibid*.
[216] Natural Resources Canada & CETC, 2006 at 56
[217] Natural Resources Canada & CETC, 2006 at 57

Monitoring costs meanwhile are not expected to be much of a factor as the IPCC has estimated them to be C$0.1 – $0.3 per tonne of CO_2.[218]

Capture costs vary greatly depending on the CO_2 flue gas concentration to be captured, as well as the type of capture method used. The least mature of the three CCS technology components, capture technology, is likely to see future costs reductions in the neighbourhood of 25-30%, and in some areas, perhaps as high as 50%.[219] The transport technology is meanwhile fairly mature, and therefore future cost reductions will mainly be achieved via economies of scale.[220] Sequestration technology in oil and gas reservoirs is fairly mature and there is not too much room for reducing this cost. Geological sequestration in saline aquifers has only seen limited testing and therefore has the potential for slightly larger reduction of costs.

5.5 Potential Concerns

Going forward there are still some concerns with CCS, for combustion sources in particular the capture stage is quite expensive and more cost-effective methods will have to be developed. With respect to the transportation and storage of CO_2 the public will have to be assured that this is a safe practice, particularly with respect to potential leakages, both those slow in nature, and large leaks that may occur at plants, pipelines, or storage sites. More research and testing will have to be done regarding the long-term sequestration, especially in saline aquifers where it will have to be established that CO_2 can be stored not just for decades, but for time spans in the thousands of years. Related to the issue of leakage, appropriate monitoring and accounting guidelines will have to be established, particularly if/when a credit system is established for the sequestration of CO_2. Lastly, it must be pointed out that CCS should not be seen as a long-term solution, but instead a technology that will help bridge the gap until the majority of our energy can be derived from non-CO_2 emitting technologies. In this sense it is important that research and funding for CCS is not done at the expense of renewables, as it is these technologies that must evolve in the long-term.

5.6 Putting it all together in the short term

The first sites to combine all three facets of CCS technology will of course be those with the lowest cost, and amongst the cheapest options are those from natural gas processing and hydrogen

[218] Natural Resources Canada & CETC, 2006 at 57
[219] *Ibid*. at ix
[220] *Ibid*.

production, which according to the literature had capture cost estimates ranging from US$13 to US$20 per tonne. These sites are located less then 600 km away from prime storage sites so the transport costs would range from US$3 – US$9 per tonne. Before sequestration, the estimated cost range is therefore $US16 - US$29 per tonne. If this CO_2 were sequestered in a non-value added site, then total CCS costs using current technology and prices would be in the range of US$19 – US$38 per tonne. If it were not for the booming Alberta economy at the moment, the cost would likely have been closer to the lower end as Alberta has a number of sites with high concentration CO_2 for cheaper capture, and many depleted oil and gas reservoirs for cheaper sequestration. However given the current high costs for materials and labour, it is likely that costs would be in middle to upper end of this range.

As all the above figures were based on literature from non-industrial sources, I attempted to verify them via interviews from industry, and the results of this analysis will be presented in the following chapters.

Chapter Summary

This chapter has established that the various technologies involved in CCS are now available and due to its vast storage potential and numerous large emitting sources, Alberta is an ideal location for implementing such a system. The US$19 – US$38 price range quoted in the last section does not factor into potential revenues generated through value-added sequestration, and as was highlighted above, within Alberta there exist a number of opportunities for EOR which could reduce the total CCS cost figure. Therefore the following chapter will look at the potential for EOR in Alberta to determine how much capacity exits, and how much this might affect the total cost of CCS in Alberta.

Chapter 6 – CCS and EOR Potential in Alberta

To get an idea of how much EOR can bring down the cost of CCS in Alberta, two factors must be considered, namely the capacity for EOR (both in terms of how much additional oil can be produced, and how much CO_2 can be stored via this production) and the price at which EOR projects can afford to pay for its CO_2. By reviewing various project reports and interviewing individuals involved with EOR projects this chapter will therefore be answering those two central questions. In addition, this chapter will also address the question of what projects are currently using this technology by taking a look at the Weyburn project in Saskatchewan. This particular project is a world leader in this area and the source of many of the facts and figures upon which I will base my analysis and conclusions.

6.1 Capacity

If there is only a small amount of total extra oil that can be produced via EOR projects then there is obviously less incentive to invest in such technology. However, just as important, is how much CO_2 is required for this additional production. Lastly, if very little CO2 can be sequestered via EOR, there is again less incentive to invest in the needed infrastructure.

6.1.1 CO_2 Sequestration Capacity from EOR

As was highlighted in chapter 5, the CO_2 capacity for EOR projects within the WCSB according to the Canada's CO_2 CCS Roadmap was 639Mt, while another report entitled 'Canada's oil sands, opportunities and Challenges' quoted a figure of 560Mt.[221,222] This latter figure only included sites with a capacity of at least 1.0Mt and thus the differences between the two are quite reconcilable. These amounts were verified in an interview with Dr. Wilson, who felt that figures anywhere from 400 – 600 million sounded about right, but he noted that these were likely the 'better reservoirs'. He pointed out that it is difficult to gauge at what point a 'depleted reservoir' becomes a 'reservoir with EOR potential' because anytime you put CO_2 into an oil reservoir you will get some oil out.[223] Thus as the price of CO_2 for the purchaser goes down (or put another way, as the cost associated with releasing it goes up for the seller) an increasing number of depleted oil reservoirs will become economical. Another factor in this equation are oil prices, as they continue to rise, more reservoirs once termed depleted will be deemed economical again. Thus while the current figures may be in

[221] Natural Resources Canada & CETC, 2006 at 53
[222] NEB, 2007 at 39
[223] Wilson Interview, see Appendix 1.4

the 600Mt range, it is worth bearing in mind that Alberta has another 800-900Mt of capacity in 'depleted reservoirs', which depending on CO_2 and oil prices could see the total EOR CO_2 sequestration capacity within Alberta rise up to 1400-1500Mt.[224] To put this figure into perspective, if we recall that 2007 annual emissions from oil sands will be in the neighbourhood of 40Mt, then a potential storage capacity of 1000Mt or greater would provide enough sequestration capacity for over 20 years, even allowing for increases in annual oil sands emission rates.

6.1.2 Additional Oil Production via EOR

Having dealt with the issue of EOR CO_2 sequestration capacity, the question of incremental oil production will now be addressed. According to a 2006 National Energy Board report, CO_2 EOR could increase conventional Canadian oil reserves "by between 8 and 25 percent, which means increasing potential recovery by between 3 and 9 billion barrels."[225] However as this represents quite a large range and applies to all of Canada, I attempted to narrow these numbers down by looking at the light/medium oil pools in Alberta to see what affect EOR would have on production rates province-wide. The cumulative original oil in place for all light/medium oil pools in Alberta is approximately 50 billion barrels. The largest 15 pools represent over 22 billion barrels, and the majority of sites looked at within this group were deemed to be conducive to CO_2 EOR with incremental recovery rate increases averaging around 15-20%.[226,227] Of particular note is the Pembina field, which has original in place reserves of over 7.8 billon barrels, and estimated rates of additional recovery of 15% via EOR. If we were to just look at the top 15 pools and figure that only ¾ were amenable to CO_2 EOR, at an average incremental production rate of 15% these very conservative parameters would lead to a figure of nearly 2.5 billion barrels of incremental oil recovery from the top 15 Alberta pools alone.[228] If we keep the ¾ ratio and the 15% figure, but now apply it to the Alberta-wide total of 50 billion barrels, the incremental oil that could be produced would be approximately 5.6 billion barrels.[229] While this is an impressive figure, particularly when you consider oil prices in the $90-$100 range, a discussion related to the costs is first necessary to put this into proper perspective.

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[224] Natural Resources Canada & CETC, 2006 at 37
[225] NEB, 2007 at 39
[226] Penn West, 2007 at 10
[227] Penn West, 2006 at 37
[228] The figure 3/4 is used because not all fields are necessarily conducive to EOR, however this figure is likely low when applied to the 15 largest fields as "most or all" appear to be amenable to EOR with CO2. Silverberg Interview, see Appendix 1.2
[229] Applying the 3/4 ratio to all fields is likely more appropriate because it may not be cost-effective to use EOR on the smallest of fields.

Figure 6 - 1 Potential EOR in AB (billions of barrels)		Additional Recovery (using a conservative estimate rate of 15%)
Original oil in place for all light/medium pools	50.0	7.5
Estimate using 3/4 of all pools	37.5	**5.6**
Largest 15 of these pools	22.0	3.3
Conservative estimate using 3/4 of the largest pools	16.5	**2.5**

Costs:

With a rough idea of how much CO_2 could be sequestered via EOR, and how much incremental oil could be produced, the discussion now turns to what the costs and net revenues of such production would be. One of the very few large scale CO_2 EOR projects currently in progress is the Weyburn facility located in South-eastern Saskatchewan, and therefore this case represents the basis for many of the cost and revenue estimates.

6.1.3 Weyburn

The Weyburn site is basically the combination of two projects that share knowledge and data with each other. The CO_2 EOR project is the currently the largest of its kind in the world and is run by the energy company EnCana, whose expertise and interest lie in increasing oil production from the Weyburn field. The other project is known as the IEA GHG Weyburn CO_2 Monitoring and Storage Project and is funded by a number of different parties, including Natural Resources Canada, the United States Department of Energy, the Alberta Research Institute, Saskatchewan Industry and Resources, the European Commission and other industrial sponsors from Japan, the United States and Canada.[230] Its mandate is to study and chronicle the movements of the CO_2 in order to assess the technical and economic viability of CO_2 EOR sequestration projects, including an assessment of the ability of reservoirs to sequester and monitor CO_2 in the long term.[231] The combining of the two projects results in a win/win situation. EnCana benefits from the information the monitoring project collects concerning CO_2 movements and flows as this allows EnCana to make adjustments which increase productivity. Meanwhile the monitoring project benefits from EnCana's reservoir engineering expertise and access to EnCana's data on the CO_2 EOR operations. [232]

[230] Petroleum Technology Research Centre, 2004 at 2
[231] Petroleum Technology Research Centre, 2008
[232] *Ibid.*

The CO_2 that is used in the EOR project comes from a gasification plant in Beulah, North Dakota and is transported the 320km via a pipeline. The plant in Beulah produces synthetic fuels and the CO_2 is an unwanted by-product that would otherwise be vented to the atmosphere, but is instead captured, purified to approximately 95%, put under pressure, and piped up to Weyburn.[233]

6.1.3.1 Costs and Revenues

In terms of costs and revenues, the cost of the IEA GHG Weyburn CO_2 Monitoring and Storage Project was over C$16 million in cash, and another C23$ million in 'in-kind contributions' (such as field support and research).[234] However of much greater relevance to this study are the costs and revenues associated with EOR project.

While the precise cost and revenue figures are not available, by first delving into an extensive report on the first phase of the EOR project and exploring the cost simulations within, and then verifying these cost estimates via interviewers, I was able to obtain the following cost and revenue estimates for the Weyburn EOR project:[235]

The initial budgeted cost of the EOR project in 2000, including constructing, operating and purchase of the required CO_2 was in the neighbourhood of C$1.1 billion, and the initial contract with the Dakota Gasification called for the purchase of about 20 Mt of CO_2 at a price of around C$18/tonne. However, construction costs have since increased, as has the value of the Canadian dollar compared to the American, so the numbers used in the economic simulations in the report were $1.32 billion in total costs, with CO_2 at C$29.85/tonne. Over the anticipated life of the project (2001-2033), it was estimated that the project would produce an estimated 133 million barrels of incremental oil. Using standard amortisation and cost of capital rates, CO_2 costs of C$29.85/tonne and on an oil price of only C$30.15 a barrel, the project would generate an internal rate of return (IRR) of greater than 10% over this timeframe. As oil prices are now in the C$100 range and extremely unlikely to ever average under $30 at any time in the future, the project's IRR will indeed be much higher then 10%, and therefore in economic terms represents a very good investment.

There were also some simulations done on a 2034 – 2053 time span, where it was determined that with CO_2 and oil prices the same as above, the project could produce an additional 44 million

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[233] *Ibid.*
[234] *Ibid.*
[235] Petroleum Technology Research Centre, 2004

barrels of oil, sequester another 26Mt of CO_2, but in so doing it would require a CO_2 credit of about C$8/tonne to get them back up to that an internal rate of return of 11%. However, again it must be pointed out that if we were to use higher oil prices (say for example just $50), then the IRR would be well over 11%, even without the credit. These findings were significant because they support the argument above, namely that as oil prices and/or costs of emitting CO_2 go up, the capacity for storage in what was before deemed 'depleted' oil reservoirs increases.

As can been seen from above, the two most variable factors affecting the profitability of an EOR field are the costs of CO_2, and the sale price of the oil, thus it is worth investigating the relationship between the two. Exact cost figures are very difficult to ascertain in this area so doing a precise sensitivity analysis involving profits based on CO_2 and oil prices was not possible, however some conclusions could be drawn. The Weyburn field is getting about 3 barrels of oil per tonne of CO_2 *injected*, however the more CO_2 that is pumped into a field, the more CO_2 that becomes back up with the oil and is recycled for reuse. Therefore a project will typically use more 'new' CO_2 near the beginning of the project as opposed to the end. Thus on a *lifecycle basis* Weyburn is getting over 6 barrels of oil per tonne of CO_2 purchased.[236] Because of other operational costs that are affected by fluctuations in oil prices it is not a strictly linear relationship between oil prices and CO_2 prices, but due to the 6-1 ratio indicated above it is safe to say that profits are more sensitive to changes in oil price then CO_2 price, and therefore if they both increase by the same percentage, net profits will for the project will improve. If we were to extend this line of thinking one step further and keep in mind that:

- The original calculations which yielded a project internal rate of return of greater then 10% were based on oil prices of slightly over $30, and CO_2 prices of slightly under $30
- Even factoring in operational costs increases due to higher oil prices, the fact that the project produces 6 barrels of oil for every tonne of CO_2 purchased would seem to indicate that project revenues are much more sensitive to increases in the price of oil then the cost of CO_2.
- Oil prices now are over $100/barrel, so well over three times the original $30 figure used in calculations

It would be reasonable to assume that given oil prices over $100/barrel the Weyburn field could likely maintain its internal rate of return even if the price it paid for CO_2 also increased to $100. In fact, given the 6/1 ratio this calculation may in fact be a very conservative one. However, it should be noted that despite various attempts to validate any of these cost and revenue figures it was very

[236] Wilson Interview, see Appendix 1.4

difficult to so as energy company employees were in many cases directly prohibited from releasing this information.

As these figures could not be directly validated I therefore attempted to verify them via other means, and as such I looked at another organisation that has an interest in the Weyburn field, namely the Penn West Energy Trust. To get some idea of the revenue this field generates for its owners I looked at Penn West's Annual report for 2006 and found that in 2006 the Weyburn field had operational costs of only C$6.60 per barrel and were generating an operating profit[237] of over C$40/barrel.[238] These are incredibly high operating profits for an EOR project and while they do not directly substantiate any of the assumptions I have made above, they do underscore how profitable an EOR project can be when paying $30/tonne of CO_2. It should also be noted that these profits were based on 2006 oil price figures when oil prices averaged around US$60, not the current price of over US$100. Thus when this is factored into the equation it makes it even more likely that CO_2 prices of $100 per tonne could support the aforementioned 10% IRR for this given project.

6.1.3.2 Sequestration

While Weyburn has proven that it can turn a tidy profit via EOR, it is equally important that the CO_2 is indeed being sequestered, and is not simply leaking back into the atmosphere. The geological section of the Weyburn report goes into great detail with respect to the trapping mechanisms, bounding seals, overlaying aquifers, the hydro geological regime, and potential pathways for migration. Having determined that: the Weyburn oil pool has effective trapping mechanism and seals, no apparent water flow from the Midale aquifer (the target aquifer) to upper aquifers, the Midale aquifer has very low flow velocities of less than 1 meter per year and favourable horizontal flow directions, and the field is located in a tectonically inactive region, the Weyburn pool has therefore been deemed to be a very appropriate location for long-term, secure CO_2 storage.[239]

To back up these findings a system model forecasted that the average cumulative release of CO_2 to the biosphere after 5000 years would be 0.2% of the initial in place CO_2 (with a 95% confidence interval range of 0.005% to 1.3% of the initial in place CO_2), and there is a 95% probability that

[237] Within the oil industry this term is described as the project 'Netback' and represents the revenue minus operational costs and royalties, however for simplicity's sake I use the term operating profit here.
[238] Petroleum Technology Research Centre, 2004 at 15
[239] *Ibid*.

98.7% to 99.5% will still be stored within the geosphere.[240] More specifically, it forecasted that 26.8% of the CO_2 in the geosphere within the EOR area would have migrated elsewhere;18.2% into the geosphere below the reservoir, 8.6% would migrate laterally within the reservoir (but outside the EOR area), 0.2% would diffuse into the cap rock above, and there would be no CO_2 that would reach the potable aquifers. In a different assessment of the leakage from the abandoned wells, it was estimated that a maximum of 0.14% (and a mean of less than 0.001%) of the CO_2 in place when EOR operations was completed would leak during a 5000 year period.[241]

6.1.3.3 Relative to other potential fields

Given current oil prices it seems reasonable that a field such as Weyburn could likely pay $100 or more per tonne of CO_2 and still turn a profit. However, one has be careful not to simply extrapolate the results from Weyburn and apply it to all potential fields because according to Dr. Wilson the Weyburn field is likely one of the best potential EOR sites in Western Canada. This is due to both its favourable geological makeup, which is good for long-term sequestration of the CO_2, and the profitability of the field, which sees it produce over 6 barrels of oil per purchased tonne of CO_2.[242] To put this into perspective, other fields may only produce 3-5 barrels per tonne of purchased CO_2, and/or have problems with heterogeneity in the field (which makes it difficult to control the flow of CO_2). A perfect example of this is the aforementioned Pembina field which is many times larger then Weyburn, but according to Dr. Wilson is going to have its good spots, but also some 'atrocious' areas (by atrocious Dr. Wilson meant that some portions of this field would likely produce very little oil and/or would have difficulties with controlling the flow of CO_2).[243]

6.2 Summary of Potential cost figures for CO_2 input in EOR Projects

The Weyburn EOR project has proven that EOR projects of its kind can pay C$30 per tonne of CO_2 and be profitable at oil prices of just C$30 per barrel. Given that future oil prices are likely to be much higher then this I have assembled some potential future cost estimates in Figure 6.2 on the following page.

[240] Petroleum Technology Research Centre, 2004 at 162
[241] *Ibid*.
[242] Wilson Interview, see Appendix 1.4
[243] *Ibid*.

Figure 6.2 - Projected Costs of CO_2 allowing for a Project IRR of 10% or greater							
Estimated Figures		CO_2 costs (in C$) given:					
		Oil/ CO_2 price sensitivity of 1.0			Oil/ CO_2 price sensitivity of 2.0		
Field	Barrels of oil produced / tonne CO_2 purchased	Oil price of $30/bl	Oil price of $75/bl	Oil price of $100/bl	Oil price of $30/bl	Oil price of $75/bl	Oil price of $100/bl
Weyburn	6	$30	$75	$100	$30	$150	$200
Average	3 - 5	$20	**$50**	$67	$20	$100	$134

In arriving at these figures, a number of assumptions and were made, firstly I assumed that due to the large 'barrel of oil produced per tonne of CO_2 purchased' ratio, the IRR of the project would have a price sensitivity of Oil/ CO_2 of at least 1.0, and likely 2.0 or higher. For fields other then Weyburn which are likely to produce 3-5 barrels of oil per tonne of CO_2 purchased (approximately 2/3 of what Weyburn would produce) a purchase cost of $20/tonne of CO_2 was selected for the first column (a cost figure corresponding to 2/3 of that of Weyburn). The purpose of the exercise above was to put a prospective price on CO_2 that EOR producers would be willing to pay so that this figure could be used in further analysis below. Due to the fact that all fields may not be as profitable and ideally suited to EOR CO_2 as the Weyburn field (which is admittedly one of the best), I have selected the rather conservative figure of C$50 per tonne for use in further analysis. Highlighted in red in Figure 6.2, this figure is based upon an average oil price of C$75/barrel, and a price sensitivity of only 1.0, both of which are likely conservative estimates which therefore take into account possible oil price fluctuations and potentially poor EOR sites.

6.3 Externalities

It is important to note that compared to non-value added sequestration, the process of EOR does produce some GHG additional emissions because of the energy required for producing the oil. There is still a net reduction of GHG emissions, however the amount depends on whether the field would have been exploited if the option for using CO_2 did not exist. In many circumstances such fields have already undergone primary conventional production, secondary water-flooding, and additional oil can only be recovered via tertiary means (whether it be the injection of CO_2, or formerly, natural gas). Thus if the field would otherwise not have seen additional recovery (which is likely the case within most fields in Alberta), then the net CO_2 savings have to be adjusted accordingly to reflect the GHG emissions produced via tertiary production.

However, if the field would not have seen additional recovery without CO_2, then all the royalties associated with theses additional oil revenues also have to be factored into the equation. It should be noted that in the case of Weyburn EnCana received a break on its royalties similar to what exiting oil sands developers in Alberta receive, namely only having to pay a very small percentage on revenues until that point in time when their capital expenditures had been reclaimed.

The Alberta government has recently announced that royalty rates will increase but as the specifics have not yet been released (the government is in negotiation with industry regarding these) it is difficult to determine the precise value of these to the government. To further complicate such a calculation, the government has specified that royalty breaks will be given for EOR and not yet specified what these will be.[244] Regardless of what the rate turns out to be, if we take the aforementioned 5.6 billion barrels of incremental oil within Alberta, and multiply it by a conservative $75/per barrel we have total additional revenues of C$420 billion. Thus even a low royalty rate on EOR will provide the province with a large windfall as it represents revenues it would otherwise not have enjoyed. It is for this reason that encouraging CO_2 EOR represents a win/win situation for the province; it reduces net CO_2 emissions while at the same time increasing both public and private provincial revenue.

6.4 Chapter Summary:

Within the WCSB there is a storage potential for more then 600Mt of CO_2 via EOR projects, a number which could more than double if oil reservoirs which are currently categorised as 'depleted' become economically viable. Via this storage a conservative estimate puts additional oil recovery at around 5.6 billion barrels of oil, and as such Alberta is a prime location for EOR projects. It is extremely difficult to say what average price EOR producers would be willing to pay for their CO_2 as this is a secretive area and to further complicate things prices will of course vary from field to field. However, for the purposes of further analysis I have settled on a rather conservative estimate of C$50 as this allows for lower then present oil prices, and also takes into account the fact that not all EOR fields may be as conducive to EOR sequestration as the Weyburn field which is the basis for my cost estimates.

[244] Government of Alberta, 2007

Chapter 7 – Credits vs. CCS

Having established that EOR could reduce CCS costs by an estimated C$50 per tonne, it is now possible to compare this with the only other viable option for substantially reducing oil sands emissions, namely the purchasing of carbon credits.[245] These credits could be purchased via a domestic trading market, and if Canada chooses to participate in Kyoto these credits could also be purchased internationally.

7.1 Domestically

The current federal government led by the Conservative party is adamantly opposed to participating in an international trading scheme as it views this as simply “throwing money away.” At a conference on environmental technologies Prime Minister Harper stated that "Our government is ready to lead the way towards real targets within realistic time frames. We will make progress, not by sending money overseas ... but by sending know-how overseas to reduce emissions everywhere."[246] Canada’s minister of the environment, John Baird has also weighed in by saying that "I certainly believe that Canadian families don't believe … it's in the best interest of Canadian taxpayers to buy credits - hot air credits in places like Russia - where we are only compensating for previous government action".[247] As can be seen from these comments, the Conservatives therefore favour what they call a ‘made in Canada’ solution which would involve the establishment of a domestic trading system, and the implementation of technologies that would reduce emissions within Canada.

To determine which of the two emission reduction alternatives would be the most cost-effective option for oil sands operators to reduce their oil sands emissions it is necessary to first determine what the future price of a carbon credit on such a domestic market would be.

7.1.1 2000 CIMS Study

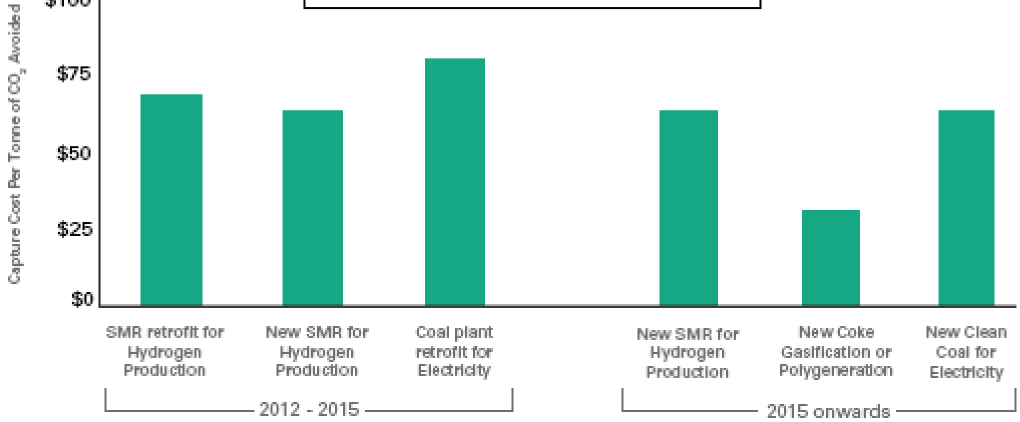
A 2000 study using a CIMS model (a new hybrid type of modeling system that combines both bottom-up and top-down modeling) set out to determine what the cost of meeting Canada’s Kyoto

[245] As was noted in chapter 4, there do exist other options that could reduce oil sands GHG emissions, such as VAPEX and Gasification, however neither will result in overall emission decreases for the oil sands, their implementation would only slow emission growth rates.
[246] De Souza, 2007
[247] CBC, 2007

commitments in the 2008-2012 time period via internal reductions would be.[248] It modeled a situation where an economy wide emission cap and tradable permit schemed was implemented in conjunction with various subsidies, regulations, research and development, information programs, efficiency standards, and the development of technologies such as CCS. It concluded that over a 10-year span, the fist 60Mts of reductions would on average cost between $10-15/tonne, the next 60Mt would cost between $30-40/tonne, while the final 60Mt would cost on average $140-160/tonne. Taking the averages of these three values, this would result in an average CO_2 price of $65.83 per tonne.[249]

The latest report by the Integrated CO2 Network (ICO2N) found that if implemented now, by the 2012-2015 period, CCS reductions on a large scale could be achieved beginning in the $45/tonne range, and averaging around $75/tonne. However, if the timescale is increased to match the time-spans used in the 2000 study, we see that costs are further reduced.

Figure 7.1 – CCS Costs (C$)



Source: ICO2N

Figure 7.1 from the ICO2N report reveals the capture costs for various technologies, including retrofits of hydrogen production facilities, new hydrogen production facilities, and clean coal plants, both in the 2012 time span, and moving forward beyond 2015.

[248] It should be noted that in comparison to a bottom up approach, CIMS models generally return higher costs estimates. This is because bottom-up approaches ignore some social costs associated with the switch to lower intensive GHG technologies which the CIMS models attempt to incorporate. Bataille, 2003 at 52.
[249] The rough calculations were as follows ($12.5*60 + $35*60 + $150*60)/180 = $65.83

With respect to the ICO2N report, it should be noted that:

- The cost figures calculated for the various forms of capture were higher then those from other studies, including MIT's recently published 'Future of Coal', and publications from the Alberta based Pembina Institute and are thus higher then figures arrived at in Chapter 5.[250]
- The transport figures used were C$15/tonne, which is higher than all other estimates this researcher has come across. (Given that most CO_2 is likely to travel 500-700km in Alberta, transport costs in the range of C$5-$10 were the norm).
- The ICO2N report does not include storage costs or potential revenue from EOR.

Before we can compare the two figures to determine the more cost-effective option there are some adjustments that first must be made. The SIMS cost figure of C$65 is in 2000 terms and thus after being adjusted for inflation at an average just under 2.5% would likely be closer to C$75 today. Meanwhile the ICO2N C$75 figure is likely at least C$5 per tonne too high with respect to the transport portion thus bringing it down to C$70/tonne. If we now factor in that it doesn't include the potential C$50/tonne revenue from EOR as was calculated in Chapter 6, then the figure is now down to C$20/tonne and represents a clear winner in terms of CCS versus purchasing credits.

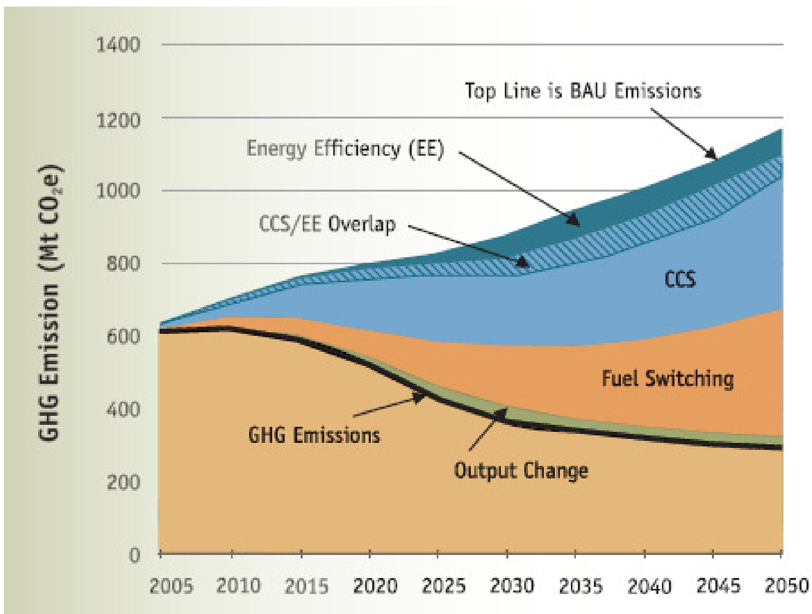
7.1.2 2006 NTREE Study

Before declaring CCS the clear winner over the purchasing of credits, another more recent study will also be reviewed. In the fall of 2006 the Canadian National Roundtable on the Environment and the Economy (NTREE) was charged with determining how best Canada could make significant GHG reductions in both the medium (2020) and long-term (2050). As was discussed previously, in April of 2007 the Canadian Federal government released its *Turning the Corner Plan* and the *Regulatory Framework for Air Emissions* which set GHG emission reduction targets of 20% below 2006 levels by 2020, and 60-70% below by 2050, however as these targets were released in 2007 they were not the initial targets for the study. The NTREE report, entitled *Getting to 2050: Canada's transition to a low-emission future* was released on Jan 7th of 2008 and found that "The

[250] There could be a few reasons for this: Firstly, the MIT report cost calculations were based on various plants in the United States, as opposed to Alberta whose overheated economy results in higher costs for both labour and materials. Secondly, as one of the co-authors of the report told me himself, there are so many variables in such a study, that if you just alter one or two slightly, the numbers can change a fair bit. Thirdly, it is worth noting that the ICO2N group is composed solely of large CO2 emitting Energy companies, who would benefit more from a report which finds high CCS prices as they can then argue that government assistance is required to implement such expensive technologies.

GHG emissions reductions modelled in CIMS can be realized through energy efficiency, fuel switching, carbon capture and storage (CCS) and overall demand reduction."[251] As with the previous study, CCS would play a vital role in future GHG reduction efforts and their simulations were once again conducted via a CIMS model. The key findings of the report were that CO_2 prices in the range of C$190 to $240 (in C$2003) per tonne would be required to achieve emission reductions of 45% below 2005 levels by the year 2050.[252] While these emission reductions are much deeper then those in the earlier CIMS study, they once again establish that even without EOR, CCS represents a better option than purchasing credits.[253]

Figure 7.2 - GHG reductions by source for 20% reductions by 2020, and 65% reductions by 2050.



Source: NTREE

Figure 7.2 shows just how significant a role CCS would play under the latest report by the National Roundtable on Energy and the Environment if all of Canada's reductions were to be made domestically.

7.2 Internationally:

If on the other hand the current minority Conservative government loses in the next election the possibility arises that a Liberal government would come to power with the support of the NDP

[251] National Round Table on the Environment and Economy, 2007 at 13
[252] National Round Table on the Environment and Economy, 2007 at 16
[253] If large scale CO2 EOR takes place within the next 30 years, then it is very plausible that by 2050 the CO2 capacity in depleted oil reservoirs will be depleted.

and/or Bloc Québécois. All three of these parties support Kyoto and thus Canada would likely attempt to meet its Kyoto targets, while at the same time perhaps changing its stance on international trading credits. This would mean that total reductions would have to be higher; however a shift in stance towards purchasing international credits could potentially also reduce emission reduction costs. CO_2 credits on the EU carbon market are currently trading at 24.75 euro, which is equivalent to just under C$40, however where they will be in 10 years time is difficult to ascertain.[254] Whether these will increase in price substantially or not depends largely on the latest round of climate change negotiations, which will I hereafter refer to as 'Kyoto II'.

7.2.1 If Kyoto II comes into force

If Kyoto II results in a strengthening of emission reductions amongst just the existing parties to the current agreement, then this is likely to increase the demand for CO_2 credits, thus driving up their value somewhat. If Kyoto II manages to incorporate the United States, (a prospect which is quite likely if the Democrats win the next election, which appears likely at the time of writing), then this would further push up the price of CO_2 credits as the United States has significant reductions to make. Thirdly, if developing countries are mandated to reduce their emissions within the next climate change agreement this would also increase the demand for the price of CO_2 credits in the future. Thus while it may be difficult to ascertain what effect all these possible scenarios may have, it would appear likely that price of CO_2 credits in the future will be higher then they are currently trading.

Given this potential scenario, what affects would this have on CCS? Without exact figures it is difficult to say with any certainty, however in the short-term it may shift some investment away from the most expensive CCS options such as the retrofitting of existing post-combustion coal-fired power plants. In this scenario it would be more cost-effective to purchase credits at prices of 60/tonne or less, and allow these plants to continue to operate as before. However, in the long-term such plants would most likely then be replaced with clean coal gasification plants which have lower CCS costs. Thus in the medium to long-term, as the costs of credits increase and the cost of CCS decrease, CSS will become an increasingly attractive option. It should also be noted that even if a Canadian government whom supports Kyoto is elected, it is quite likely that they will still maintain the 'made in Canada' route and obtain emission reductions domestically.

[254] Price of EU CO2 credit in C$ on April 25th. Point Carbon, 2008

If Kyoto II does not come into force

If Kyoto II does not come to fruition, then it is possible that the price of international CO_2 credits would go down. However under such a scenario it is not likely that a Liberal government would purchase credits because their sole reason for purchasing them would have been to live up to their Kyoto II commitments. This would bring Canada back to the situation above where it relies on domestic reductions to reduce its emissions and therefore CCS would still be the most cost-effective alternative.

7.3 Chapter Summary

Given the studies outlined above, when compared to undertaking CCS in conjunction with EOR, in almost all scenarios it appears as though the purchasing of credits would be a much *less* cost-effective solution to reducing Canada's CO_2 emissions. The only potential exceptions to this would be if oil prices dropped so dramatically (to a price of C$20-30) as to reduce the profits associated with EOR, and/or if a Canadian government elected to reduce their emissions almost entirely via international credits and these credits could be purchased for less then C$20/tonne (12.50 Euro). As both of these scenarios are extremely unlikely, CCS in conjunction with EOR is clearly the most cost-effective technology for substantially reducing Canada's CO_2 emissions within the next 10-15 years.

Chapter 8 – Hurdles to Implementation, Suggested Solutions and Conclusions

The body of this report concluded that the implementation of a large-scale CCS network in Western Canada represents the most cost-effective technology for dramatically reducing Canada's GHG emissions in both the short and long term, while at the same time allowing development of the vast oil sands operations in Alberta. The final sub-questions to be addressed regard what the major hurdles are to making this a reality, and how these hurdles may be overcome.

8.1 Hurdle - Public Acceptance

One potential hurdle is that of public acceptance, because the general public may be leery of pumping CO_2 into the ground due to fears that this could result in potentially fatal leaks under poor monitoring situations. This is likely less true of populations living in traditional oil producing areas as they are accustomed to the pumping of various solvents into the ground, however even the inhabitants of such areas may become nervous when made aware of the potential scale of larger projects whose goal may be to sequester 10 million tonnes of CO_2 a year.[255]

8.1.1 Suggested Solution:

By investing in public awareness campaigns and ensuring that proper sequestration and monitoring criteria are in place, this is likely not going to be a major issue moving forward. This is supported by the findings of a study carried out via surveys conducted in 2004 and 2005 which indicated that the majority of Canadians see CCS as an appropriate technology for reducing GHG emissions, particularly if appropriate regulations are in place. However it is worth noting that the majority viewed it more as bridging technology to be used until other solutions such as renewables are developed.[256]

8.2 Hurdle – EOR projects are more sensitive to price fluctuations then conventional projects

As this report has shown, EOR can both bring the costs of CCS down considerably, as well as provide additional income for government in the form of additional royalties. However, relative to conventional oil projects EOR projects are more vulnerable to oil price fluctuations and to date this has limited the number of such projects undertaken.[257] There are a couple reasons for this, firstly

[255] Interviews, Beynon, Wilson, see appendices 1.3 and 1.4
[256] Amey, 2005 at 5
[257] Beynon Interview, see appendix 1.3

EOR projects generally have higher operating costs then conventional oil projects and thus a fall in oil prices will harm them first. Secondly, to secure contracts for the delivery of CO_2 the buyer generally gets a lower price if they agree to purchase a fixed amount each period. Thus while a conventional oil field can simply turn off the pumps if a substantial fall in oil prices renders project revenues less then operational costs, EOR projects have the additional cost associated with the CO_2 it has agreed to purchase. While a sharp reduction in oil prices does not appear likely at this point, it is a factor that EOR firms must consider before both committing large amounts of capital for the necessary infrastructure to undertake EOR, as well as entering into contracts for the purchase of CO_2.

8.2.1 Suggested Solution:

To help minimize this risk one possible solution would be to provide tax or royalty breaks for EOR projects when prices dip below a certain WTI price. The costs of implementing such a solution would likely be quite low as this is not dissimilar from some of the current royalty arrangements that levy varying tax rates depending on the oil price. In the off chance that the government should experience some revenue losses during periods of low oil prices this would most likely be offset by the additional revenue generated via projects that may not have been initiated if not for the legislation. Therefore this represents a low cost, low risk solution for government which could result in more EOR projects getting off the ground.

8.3 Hurdle - Cost

The most prominent hurdle facing the establishment of a large scale CCS network are the significant upfront costs that must be undertaken to capture and transport CO_2, and therefore creative and innovative ways of bringing these costs down must be explored.

8.3.1 Suggested Solutions:

As was mentioned earlier, the Weyburn project was in part so successful because it received a favourable royalty rate from the Saskatchewan provincial government similar to that which helped encourage early oil sands development in Alberta. The assurances of a preferable royalty regime for EOR projects in Alberta would help spur investment in EOR projects and in the long-term such a decision may even prove to be tax neutral as additional EOR projects would likely to be undertaken. In the short-term the government could more then offset this small revenue loss by raising royalty rates on oil sands development as these projects have now reached maturity and are experiencing record profits.

The Weyburn project has proved very successful in demonstrating the technical and economic viability of both EOR and CCS and has thereby drawn global interest from parties interested in investing in similar technologies. Government assistance for a clean coal power plant project which incorporates CCS with EOR could provide the necessary incentive for first movers to demonstrate the feasibility of this technology and thus bring additional private funds to the table. This suggestion definitely has the backing of the aforementioned David Keith, Canada Research Chair in Energy and the Environment, who stated that "More research could make carbon capture and storage cheaper, safer and more widely applicable, but at this point, we don't need more research to go forward. We need action. The best single way to learn more about carbon capture and storage is to do it, do a major project." [258]

What is really needed to facilitate large-scale use of CCS in Alberta is a backbone pipeline to connect the large emitting sources with potential storage areas. For the oil sands producers to be brought into the mix, a pipeline would therefore have to be constructed from the Fort McMurray region to central Alberta. The Alberta government has recently announced that it will soon be implementing intensity targets for the largest industrial emitters requiring them to reduce their GHG emissions by 12%. Those that are unable to meet the targets have the option of buying carbon offsets or paying a $15/tonne charge into a climate change fund.[259] One option would be for the proceeds of this fund going towards the building of the backbone pipeline thus bringing down the cost of CCS via private sector funds. This option represents a win/win situation for the Alberta government as the private sector emitters will either be reducing their emissions directly today, or helping to pay for infrastructure the can help reduce emissions in the medium-long term.

8.4 Hurdle - Lack of regulation

What really exacerbates the cost problems are issues regarding lack of regulation. Companies are particularly unwilling to proceed with large capital outlays if they don't know what the regulatory framework will look like in a few years time. In the course of the research interviews this was a common theme, many of the interviewees mentioned instances where they had heard of potential

[258] Amey, 2005 at 5
[259] De Souza, 2008

CO_2 reduction plans fall apart at the last minute, simply due to the uncertainty of regulation which has been constantly changing in Canada the last five to ten years.[260]

8.4.1 Suggested Solutions:

What is therefore needed is long-term certainty in the regulatory framework which matches the long-term nature of the CCS investments. This sounds simple enough, but when industry is trying to make long-term strategic investment decisions, particularly regarding the large initial outlays involved in CCS, they need a degree of price certainty and regulatory stability. Industry needs to know what the costs and incentives of producing CO_2 will be, and without this, industry is not likely to invest in the costly infrastructure associated with CCS. A very telling statement by the standing committee charged with investigating the oil sands reflected this issue in particular: "The Committee heard experts say that the industry already has all the technology needed to produce non-polluting energy. What are really missing are the conditions that would encourage the private sector to invest in that technology".[261]

<u>8.5 Other Findings:</u>

8.5.1 Interviewees unanimous regarding establishment of CO_2 network within 5-15 years.

When asked if they foresaw a CCS network being established within Alberta in the next 5-15 years each of those interviewed answered in the affirmative. Thus despite the obstacles listed above, these experts felt they could be overcome, and that CCS will make up the predominant emission reduction strategy for Canada in the near future.

8.5.2 There is no one silver bullet

At one point the focus of my paper had been to try to determine what single CO_2 mitigation technology provided the most cost-effective opportunity for reductions in Canada. However in the course of discussions with interviewees it became apparent that given the enormity of Canada's GHG gap, and taking into account how varied the respective provinces are in terms of their regional geology and economies, different mitigation strategies would be more effective then others depending on the region. Keeping with CCS as an example, it would be more expensive to undertake it in some eastern provinces as they don't have similar geological storage capacity for

[260] Beynon interview, see appendix 1.3
[261] House of Commons, 2007 at 24

CO_2, and it would therefore require the establishment of extremely long pipelines. Similarly, largely flat provinces such as Alberta and Saskatchewan which have less hydro and more coal burning power plants have more large CO_2 emitting sources; which combined with the nearby massive CO_2 geological storage capacity makes CCS a more cost-effective option. As a result, on a Canada-wide basis it was the conclusion of most of the interviewees asked that Canada would have to rely on a multitude of mitigation strategies. However, they also acknowledged that of all the current options, CCS most likely represented the mitigation opportunity with the largest potential, an opinion that was also reported in the NRTEE publication and reflected in Figure 7.1.

8.5.3 Time is of the essence!

Some oil sands producers are already switching from natural gas to gasification using petroleum coke as the fuel source because this greatly reduces their reliance on natural gas.[262] While these gasification plants are particularly well suited to CCS (as they have a higher purity CO_2 stream and therefore lower capture costs), if they are not equipped with capture technology they emit much more CO_2 then natural gas powered plants. If producers are aware that a CO_2 network is being established in the near future they will be more likely to make the plants capture ready now, because although a retrofit is costly, having expensive equipment sitting inactive is even more so. As the supply of natural gas decreases and/or prices increase, it will make increasing sense to use the remaining natural gas for the heating of homes as opposed to using it in oil sands production, thus the incentive to switch to petroleum coke gasification will only grow over time.[263]

8.5.4 Oil Sands Producers are not likely to be amongst the first to take part in CO_2 EOR

With CCS and EOR the CO_2 purity is very important, because the higher the purity, the lower the costs of capture and transport. Coupled with the fact that oil sands producers are located further away from potential EOR sites, the result is that oil sands producers are not likely to be the first industries to sell their captured CO_2 to EOR producers. In all likelihood this will be chemical plants, refineries and newly built clean coal-fired power plants, which all have higher purity CO_2 streams and/or are located closer to potential EOR sites. *I should emphasize that this does not mean that CO_2 EOR will not assist oil sands producers to reduce there GHG emissions in the future*; quite to the contrary in fact. This report has illustrated how the revenues from EOR can help offset the large upfront capital outlays associated with CCS infrastructure (pipelines, retrofitting of refineries,

[262] One such example is the Long Lake project. Long Lake Project, 2007
[263] Beynon interview, see appendix 1.3

power plants, etc) and thus spur investment into a CO_2 network, and as such EOR can play an extremely valuable role in reducing the cost of such a network.[264]

8.6 Conclusion

During the course of my research, and particularly in the interviews, it became evident that some of the very largest CO_2 emitters in Alberta are willing to retrofit their plants (at their own expense) so they can capture and sell them their CO_2. The only thing stopping them from doing so is the lack of long-term rules and regulations upon which to base their negotiations with EOR project owners. Thus while the implementation of all the above solutions would be helpful in establishing a comprehensive CCS network in Alberta it is the opinion of this researcher that the two most important government actions would be:

1) Implementing a royalty regime which gives EOR producers royalty relief for a fixed period of time, thus encouraging more EOR projects.
2) At both the federal and provincial levels, implementing regulation with respect to CO_2 emission reduction targets as well as setting out precise fines for breeching these targets. This should be coupled with legislation setting out any other incentives or penalties that firms may encounter, and of equal importance is the requirement that all such legislation should be long-term in nature so that private industry can plan accordingly.

The governments in Canada are currently presented with a real opportunity to spur private investment into expensive CCS infrastructure. With the proper incentives and regulatory framework in place, a number of EOR companies would be willing to invest in a technology that will provide them with viable projects and reduce GHG emissions. These projects will contribute to CCS infrastructure, and if implemented correctly this can be accomplished at little or no additional cost to the taxpayer. With such a CCS infrastructure in place Canada can indeed continue producing oil via the oil sands, while at the same time meeting its reduction targets.

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[264] In the very long-term EOR is not likely to have the capacity to continue taking large amounts of CO2, eventually this will have to be sequestered in non-revenue generating sites, such as deep saline aquifers. However, by this time (perhaps 30 – 40 years from now) it is reasonable to assume that prices of capture will likely have decreased, CCS costs would be lower then the costs associated with releasing carbon, and EOR will have played a valuable role in doing so.

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Appendix 1.1

Date and time of interview: December 6th, 2007 at 13:30pm, MT time.

Interviewee: Dr. Stefan Bachu, Senior Advisor Alberta Energy and Utilities Board

The style of transcription used was what Kvale would describe as a narrative one, thus removing any repetitions and pauses, as well as making the transcript more readable without altering the meaning or general sentiment of the interview. The reason for selecting this style was because the transcripts' intended use was to convey the general views of the interviewee (as opposed to being used for any linguistic or psychological analysis for example, which would generally require a precise verbatim transcription).

The phone interview stared with Dr. Bachu inquiring about the nature of the program and whether the project work was more technical or general in nature. I informed Dr Bachu that was a thesis project in an Environmental Masters Program from a university in Roskilde, Denmark, and with respect to CCS the project describes the technology, but is more general in nature as one of the primary objectives is to determine what the potential for CCS is in Alberta. I then asked if Dr. Bachu had had a chance to read over the questions and whether it was acceptable for the interview to be taped for the purpose of future transcription and inclusion in the thesis. Dr Bachu kindly consented so I turned on the tape recorder and placed the phone on speaker phone. What follows is a transcription of the interview.

C.B - Okay, can you hear me all right?

S.B - Yup

C.B - Perfect, I guess I'll just start by asking, in your personal opinion, what do you think the potential for carbon capture and sequestration is within Alberta?

S.B - In broad terms the potential is significant. From two points of view, one, that we have large sources of CO_2, either from coal-fired power plants, oil sands plant, refineries gas plants etc, and also because we have the necessary and suitable geology and sedimentary succession. Between the two of them, this allows for capture and storage.

C.B - Okay, thank you. What do you see as the major hurdles to implanting a large-scale carbon capture and sequestration network in Alberta?

S.B - There are two major hurdles, there are also some smaller ones (not that I would call them insignificant), but there are two major hurdles. One is of course the financial aspect of the implementation of this mitigation strategy, because carbon capture and sequestration is a cost, the industry will not make any money from it and the cost has to be brought down, or implementation has to be facilitated. Another major hurdle is lack of a proper regulatory and legal framework that will allow large-scale implementation. You should be aware that this issue (rather neither of these issues) are specific to Alberta. They are applicable anywhere in the world right now, there is no financial incentive anywhere to do it, and there are no regulatory or legal frameworks anywhere else either. Basically we are not better or worse off than other jurisdictions, in certain aspects maybe better. But nevertheless these hurdles have to be overcome.

C.B - What kind of incentives do you think would have to be required to overcome these hurdles?

S.B - I have less experience and familiarity with the economic and financial aspects and I would rather leave that to those who know. In my opinion regardless of the way in which it comes about, the consumer will pay the price in the end. It will be either a tax or an increased cost for the products; whatever the product is, whether it is energy, etc, the cost will be borne by the consumer (taxpayers or purchasers). So what form that will take, a carbon tax, incentives from the government (which also come from general tax revenue), special fees, or god knows what else, that's in my opinion, a minor detail.

C.B - From what you know, and from how things stand, do you anticipate that there will be a large CO_2 pipeline network established within Alberta in the next 5-15 years?

S.B - I would have to say yes, within the next 5-15 years it will start slowly and it will develop. So, yes, but it requires lots of money to build it, and this is a significant investment that will not produce for quite a while. By the way, this is another hurdle that has to be overcome, the lack of infrastructure. Just developing the infrastructure necessitates a huge investment and that investment may sit idle for a period of time until it will reach full capacity, so that is another issue.

C.B - So leaving potential revenues from EOR aside for the moment, what would you say the cost range would is for just the capture and transportation of high purity CO_2?

S.B - Well, again, I am not an expert in financial matters, and have I no interest in paying attention to that. My expertise is in the geological storage aspects, so I wouldn't venture to give any numbers.

C.B - Okay, I'll skip over the economic numbers then. I understand you were just at some meetings in Calgary, were there any recent interesting developments that you could perhaps share with me?

S.B - Ahh, no, well that depends. I was involved in an international workshop preparing recommendations for the G8 leaders next year in Japan, but these are confidential as they will be presented to the G8 leaders. And I had some meetings with industry in Calgary which again are confidential.

C.B - Okay, of course. Would you care to comment on the Federal and Provincial governments' stances on CCS and how this might affect its implementation?

S.B - It seems that both governments are starting to understand that this is an option that offers significant potential for reducing CO_2 emissions in Western Canada, particularly in Saskatchewan and Alberta. They support it because it is a made in Canada solution, whatever money will have to be invested (and this will be a significant amount) will be invested in the country as opposed to going out of the country to buy credits and offsets and so on. But I'm not sure that the governments understand yet the full magnitude of the efforts required, also their role, even outside financial matters.

C.B - Okay, thank you very much. Are there any other individuals you would recommend I try to talk to regarding CCS and/or EOR?

S.B. - How long are you going to be around?

C.B - I'll be here for another week or so.

S.B - You may want to talk to Bill Gunther at the Alberta Research Council.

C.B - Okay, thanks.

S.B - You're welcome.

C.B - Well thanks so much for your time. When I've finished transcribing the interview I'll be happy to send you a copy of them.

S.B - That will be interesting, I'll appreciate that.

C.B - Okay thank you very much, and best of luck to you.

S.B - You too.

Permission to record and Transcribe the Interview:

With your consent I would like to tape record the interview so that I can transcribe the interview and include the transcriptions in the appendices of my thesis. The knowledge gained through the interview will generally be summarized in the body of the thesis, however selected quotes, facts and/or figures may also appear in the main thesis (again, with your consent). If you would prefer to keep any information confidential, whether it be your name, your company, a particular project, or any project specific information I will of course respect that and not include it in my thesis or any appendices. Once I have transcribed the interview I would be happy to send you a copy to ensure that I have not made any errors and that you are comfortable with it as is before it is included in the appendices.

Post Interview thoughts:

Dr. Bachu is understandably a very busy man and therefore before the interview got underway he informed I that he could not answer too many questions. I respected this wish and as a result did not pose many follow-up or probing questions. In retrospect I felt that he should likely have posed one or two, particularly with respect to why the Dr. Bachu mentioned the provincial governments of Saskatchewan and Manitoba in particular. (It later turned out that he meant Alberta, not Manitoba). This may also have been do to the fact that this was the first interview, and I kept this in mind for future interviews so that this mistake would not be repeated again. In addition, after of one of the responses it became clear that questions pertaining to potential cost figures should be dropped from the interview. In doing so however, I inadvertently also skipped over a question pertaining to the publics acceptance, and how this would affect its implementation. This was not deemed a vital question for the purposes of the investigation; however it once again provided I with a learning experience with regard to how such situations should be handled in the future. In particular, it revealed to I how important it is to quickly read over the potential list of questions once the interview is complete, and to not become flustered just because the structure of the interview has altered slightly.

I had initially planned on asking the Dr. Bachu whether he had any questions, or additional information to add (as recommended by Kvale), however as I had already asked an additional question about the recent Calgary meetings and whether anything new could be shared from this meetings, I skipped this step and simply thanked Dr Bachu for his time.

Appendix 1.2

Interviews with Shane Silverberg of Penn West

Part I - December 13, 2007

After chatting briefly about my program, Shane said it would be fine to tape record the interview and what follows is a transcription of this conversation. The style of transcription used was what Kvale would describe as a narrative one, thus removing any repetitions and pauses, as well as making the transcript more readable without altering the meaning or general sentiment of the interview. The reason for selecting this style was because the transcripts' intended use was to convey the general views of the interviewee (as opposed to being used for any linguistic or psychological analysis for example, which would generally require a precise verbatim transcription). Shane had been provided with a list of questions beforehand, so when these questions were not read allowed, they will be inserted in brackets with italics (*as such*).

General CCS Questions:

C.B - (*In your personal opinion, what do you think the potential for CCS is in Alberta*?)

S.S - I'm not going to give you my own personal opinion on CCS, (what) I'll give you (is) our organisations.

C.B - Sure.

S.S - Penn West's feeling on the potential for carbon capture is that regardless of whether or not you believe the rhetoric put forward by Al Gore, i.e. that industrial waste gasses cause global warming (Penn West I believe does believe that there probably is a link), our feeling is that if you look at the technology of CO_2 enhanced oil recovery as something that makes business sense, and a good by-product that it makes environmental sense. It doesn't have to make global warming sense, if it makes sense from a global warming point in that it sequesters CO_2 and prevents global warming, that is a VERY positive by-product. Still, there are a lot of industrial complexes around this province that come from the oil sands, and just around the province in general, that are emitting industrial waste gasses. It's not just CO_2, but sulphur particles (for example). Our feeling is that the smokestacks around these larger complexes there is a benefit for more then just Penn West. Penn West gets the benefit of the captured CO_2 as it helps with the EOR production, but it also helps clean up the atmosphere around the sites, around Fort McMurray for example. Our feeling is that there is a benefit for those living around where the industrial waste gasses are emitted, but it also benefits the government because if we are able to produce light oil as a result of enhanced oil recovery, the provincial government sees more oil revenue through royalties for the province. Thus if you look at it from a business point, the environmental positives that come along with it (…inaudible), but the driver has to be that the project is economical. That's why some of our investors might wonder why we have been aggressive with on the R & D side….but we are not just going to go out and pay tribute to the CO_2 reduction, and hence do a project that is uneconomical, you can't run your business that way. If we can capture the CO_2 in a manner that results in a project (with a return) our investors are looking for, then this is something we do see ourselves going forward in.

Our feeling is that the public in Alberta is on side with CO_2 sequestration, and the public in Canada is generally onside. The provincial government in Alberta is onside, and the federal government in

Ottawa is starting to understand the importance, so it has been an effort to get all sides on board, and all the while we have been at different stages of CO_2 flooding.

C.B. - (*What do you see as the major hurdles to CCS in Alberta?)*

S.S - I think it is sort of a carrot and stick situation, without the carrot there (are no) incentives, so in the end it will take a combination of both (5 seconds inaudible). I think the ICON group identified a number of hurdles, they put out a whole pamphlet on that (….inaudible). I think they would like a lot of government involvement, taxpayer involvement, I think they want to pass the burden on to the taxpayers (…inaudible) via byproducts (….inaudible). For us, initially we felt that we could take on a lot of the costs ourselves in terms of the capture and piping of the CO_2 (inaudible…….).

C.B - Sorry, I can't quite hear you. Sorry, the last sentence again there?

S.S - I think that Penn West is very aware of the fact that government involvement may be necessary to take this forward. But you don't expect the taxpayer to necessarily take on the burden for this. It may be that government push industry, through tax cuts, government taxing, etc. And some of these tax plans harm taxpayers anyway. If you look at cold fired generating facility, if the government were to penalize the coal fired generation facility, the coal fired generation facility will jack up the prices on electricity for the end user, and eventually the cost gets passed on that way. It's the same with refineries and upgraders, if you tax them they will pass it on to consumers via higher oil prices. So at the end of the day it comes down to what people believe, whether it comes out of there pockets via taxes (or higher prices….) but Penn West doesn't really get into this philosophical side of the debate, we just want to run our business.

C.B - So it would be safe to say that even without government incentives you can see that Penn West has opportunities to earn a profit as is.

S.S – Oh, most definitely. We have involvement in three commercial projects right now using CO_2. One is at our Weyburn field in Southeastern Saskatchewan where we are a working interest partner with EnCana. The other is at Midale filed (…inaudible). We have a 21% interest in Weyburn a 9% interest in Midale and we are also involved in a commercial project in Joffre which I know you are aware of. Our project at Joffre has been operating since 1982 and it's a very interesting case which I'm sure we'll discuss more. The pilot projects that we're operating right now, two of which are at Pembina, one is a pilot that we've had on since the spring of 2005 and the other is a pilot that is just starting up right now, a horizontal pilot, using horizontal wells. We've also just announced in a press release that went out yesterday that we are going to be CO_2 flooding our South Swan Hills projects (a former hydro flood area) and we see these projects being economical going forward. Again, the cost of capture is significant, in an environment such as the oil sands with a lot of labour, infrastructure, and resources. It is tricky getting these projects up and running.

C.B - Can you comment on some of the potential costs of capture, the ranges between when you have the real high purity CO_2 from for example a chemical plants or fertilizer plant, is this where you would be getting most of your high purity CO_2?

S.S - Right now we have talked too everyone, we've talked to people who are involved in power generation, so coal fired power generation facilities, we've talked to refineries and upgraders, we've talked to chemical plants as you just mentioned. There are a number of facilities that have been yet to be built, but are planned for the near future so we've talked to the people behind those projects as well.

I think there are a lot of opportunities, but again industry expects the person who is going to purchase the CO_2 to pay quite a significant amount, and we don't feel that we should be experience the full burden of the cost when the emitters have an issue themselves (putting them up the stacks, etc). The government announced not too long ago that they are going to be putting a fine on the 100 largest emitters, and that fine is a $15/tonne fine. I think the fine kicks in the summer of 08; you would want to clarify that …

C.B -Yeah, I'll look that up for sure, that's interesting.

S.S - Penn West is willing to pay a certain amount for our CO_2 and the fact that the government is putting that penalty on the 100 largest emitters. They want to sell it for a certain dollar amount, we want to buy it for a certain dollar amount, but there is a gap there, and the gap is about a $30 gap.

C.B - Wow, okay, that is quite substantial

S.S - The $15 a tonne penalty brings us closer together, but there is still a $15 gap. Maybe as costs in the province come down, if they do come down, and it looks like they are coming down right now as the result of the royalty increase and the desire (inaudible ….) natural gas prices, causing them to build less and causing costs to come down. If there is an opportunity to do a retrofit for less, then this gap between the buyer and seller might come together.

C.B - Is that just a reflection of the costs of labour and material within Alberta now?

S.S - Costs of labour, costs of materials, basically costs of labour. All the projects up in the oil sands have basically been driving up the prices throughout the province.

C.B - (*What pre-conditions would have to be in place for large scale implementation of CCS?)*

S.S - We are basically looking at government penalties so that emitters will capture their CO_2 and sell it for a price that is economic (for us).

C.B - You need some kind of framework..?

S.S - Some kind of preliminary pipelines, routing, and various things if we could strike a deal with them to lay down some pipe and get the pipes to our field. I mean it takes time to build, and would have to have consultations with those people who the live in the areas where the pipes would be traveling through, just to make sure they are okay with a CO_2 pipeline in their backyard. It's not like it's H2S, this is not a poisonous gas though, there are not a lot of issues with pipelines.

C.B - (*What kind of incentives would be required?)*

S.S - Either incentives for the capture side, or penalties for the emitter, or it could be a combination of both.

C.B - Yeah, we've actually covered a lot of these questions throughout your discussion, it's been quite interesting, so that works…

C.B - How does CCS compare to other CO_2 mitigation options available?

S.S - I think the ICON group has talked about capturing the CO_2 and putting it in coal seams, abandoned mine shafts and geological formations, etc. As far as we're concerned, if you are going to put it into the ground there should be some positive outcome. If you are going to sweep the problem under the carpet (inaudible….) how about have a positive outcome. I think no matter how green you are, most people still drive cars, most people still want to heat their homes, and having oil is not a bad thing. Again I'm relatively environmentally conscious (this may sound strange when I work in the oil patch, but I'm a sociologist), I care about the environment. (Inaudible…). At the end of the day people need petroleum products, it's in everything they buy, plastics, etc. At the end of the day, if we can actually take the CO_2 and stick it into the ground, do some positive for the environment, and get oil out of it, it has a double benefit.

C.B - Yeah, I completely agree.

S.S - At a certain point a field can only produce so much from water flooding. If you look at the Joffre field, it's probably been under production for 50 years. They shut the field in, in 1977, and after oil prices rose with the oil embargo, it made sense to find innovative ways to get oil out of the ground. People down in the US starting tinkering around with EOR and decided to give it a try. (Inaudible…) The field originally came under CO_2 flood in 1982 and has produced an additional 11% of oil in place, and we suspect that ultimately this will be 15% in total.

C.B Okay…

S.S - If you look at the Pembina field that we are really keen on flooding with CO_2, it's a 7.8 billion barrel field.

C.B - Yeah, that's a massive area, isn't it?

S.S - Yeah and according to the estimates there is probably more then 80% of the oil still in the ground, even though the field has not been productive for many decades. If you only got 1%, that's over 7 million barrels, so if we can get an extra 10% out, that's 780 million barrels, so again that's a big prize. Everybody gets all excited about the heavy oil, but there is still a lot of light oil in the province, just have to be innovative to get it out.

C.B - Yeah, I totally understand.

S.S - Just to give you a heads up, I have about 8 minutes left, but we'll have a follow-up conversation.

C.B - Okay, we've kind of covered the federal and provincial stances there…

S.S -You're wondering what the Alberta-wide (and/or Western Canada) potential is for EOR projects?

C.B - Yeah, definitely.

S.S - If you go to our website and pull up a presentation (you can do this later), slide 10 outlines the 15 largest light/medium sized oil fields in the province. Penn West has a big presence in 6 of them: Pembina, Swan Hills, Redwater, Willesden Green, Mitsue, Virginia Hills. Our feeling is that most or all of those fields will be amendable to CO_2 EOR. For the other fields in the top 15, there is a high likelihood that they will be amendable to CO_2 EOR as well. We generally only comment on the fields that we are involved in, but our president though, when we go out on investor road shows etc, there will be occasions where investors will say "I know you are not involved in the Judy Creek Pool, or Turner Valley Pool, or Bonnie Glen, or Ferrier, or Nipisi, but what's your feeling whether they would be amenable to CO_2 flooding?". There are a couple factors (and I'm not an engineer, but we could certainly put you into touch with our engineers), there are certain factors that help make a field amenable to CO_2 flooding and they have to do with issues of permeability and verosity, the type of sand, if there is (inaudible). If you want to predict whether a field will take well to CO_2 flooding, one of the key issues is to look at how successful the water flood was, that will give you some sense of it. Also if you have done a hydrocarbon miscible flood first (for example an ethane flood, where you are actually pumping natural gas into the field), that will also help give you a sense of how successful you will be with CO_2. However these pilot projects are the real tests, where you are actually putting the CO_2 down there.

C.B - Like the Weyburn site, and the Joffre site.

S.S - Exactly. One of the analogies that may help you think of CO_2 flooding (I'm sure you are already very clear on how it works, but we'll often give this analogy to investors so they can better understand it) in terms of providing the difference between primary, secondary and tertiary recovery, a very elementary analogy is: If you were to go to McDonalds for lunch and get a Big Mac, and you are eating it and get some grease on your sleeve, primary recovery is the equivalent of wiping your thumb across the stain. You'll get some of the grease off your shirt, but you're going to leave most of it behind. Secondary is going into the washroom and running your shirt under the faucet; the water will wash some of the grease out, but again leave much of the grease behind. CO_2 EOR is a lot like taking your shirt to the drycleaner; they'll put a chemical dry-cleaning fluid on the stain and what the dry-cleaning fluid does is it mixes with grease and helps to lift the grease off the fabric so it can be washed out. CO_2 works the same way, at high pressure, CO_2 becomes near liquid (you can actually turn it into a liquid, but for CO_2 flooding it doesn't have to be liquid, you just inject it at a near liquid state)

C.B - That's that supercritical state, is it?

S.S - Yeah. The actual terminology you would probably need an engineer to walk you through it, but I know that a certain pounds per square inch (PSI) it becomes what is called 'miscible'.

C.B - Yeah, I've come across that terminology.

S.S – At that state the CO_2 will combine with the oil and it expands the oil and helps to allow you to push that oil off the rock. After the primary production and secondary water flood you have left certain amounts of oil behind, the oil that doesn't really want to move, it's stuck on the rock. The CO_2 expands the oil off the rock and helps you to push it out, just like the dry-cleaning fluid helps to expand the grease of the fabric of the shirt.

C.B - That's a good analogy

S.S - It's simple technology, it's nothing fancy, you're just helping to expand the oil of the rock so you can push it out. There are certain issues involved, if you do a water alternative gas injection, where you are injecting water, then you are injecting gas, then water, etc. The combination of the CO_2 and the water can be quite corrosive, so you need special infrastructure in terms of lined pipe, or stainless steel pipe, so you don't have to worry about the pipe corroding. So you do have to take into consideration the infrastructure at the field level so it doesn't get destroyed by the CO_2. The good thing about CO_2 EOR is that CO_2 is relatively worthless, so if it stays in the formation it's not a big deal. You tend to recycle about 70% of the CO_2, as you first push it in you are not going to see much come back out, but as the phase of the project continues you will see more and more of the CO_2 produced with the emulsion, with the oil. Then you can separate the CO_2 and send it back down, so the cost actually does down with time because you don't have to keep putting in as much new CO_2.

C.B - the initial flood is when you are putting in a larger portion of the CO_2, is that right?

S.S - Yeah.

C.B - Until breakthrough, is that what the terminology is?

S.S - Breakthrough has to do with….You need good containment for the CO_2 so if it's in the reservoir you don't want it to exit. We've had excellent containment at Pembina which basically means that it's being kept in the areas where you want it to stay. But I would hate to give you the wrong explanation, so you would probably want to confirm exactly what containment means by talking to one of our engineers.

C.B - No, that's perfectly all right, that's cool.

S.S - I do have to run now, but we'll hit the rest of the questions soon, when is a good time for you?

C.B and S.S discuss when would be best to talk again and have a brief chat about their respective scholastic endeavors.

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Part II of interview, Monday December 17th at 9:00 am MST.

As we didn't get through all the questions during the first interview, Shane was kind enough to pick up where we left off.

C.B - As things stand now, do you anticipate that there will be a CO_2 pipeline network established within Alberta in the next 5-15 years?

S.S - I think it will happen in the near future, with discussions getting more serious the next 2-5 years and it getting constructed in the next 5-10 years. That is sort of my feeling; however our president, Bill Andrew, may feel a little differently. Again these are just my opinions, what I've heard.

C.B - Well, that's what I'm looking for so that's great.

C.B - (*What kind of government action or program would be required to bring this about)*

S.S - I think again that it would be more stiff penalties on the emitters. Either that or a combination of credits and penalties. I don't think that credits alone will do it; I think it would either have to be penalties, or credits and penalties.

C.B - (*If some sort of carbon tax were introduced, Penn West seems to be strategically well placed with respect to other energy companies, would you care to comment on that*?)

S.S - Yeah, I think we are well placed, I think the two best in Canada would be ourselves and EnCana. There are few other organisations that are working on projects (inaudible…) down at Midale, and I think Devon has a project in around the (inaudible) area, right off the top of my head I'm not sure, but I know it was mentioned in one of their presentations. In terms of number of projects I'd say that ourselves and EnCana are probably the (*best positioned*). They have the Weyburn project, a field we do share in the knowledge of. We also have knowledge coming to us from Midale, Joffre, the two pilots at Pembina as well as the Swan Hills pilot.

C.B - Yeah, I was just reading a press-release about the Swan Hills project and a deal you made with the Alberta government, some kind of relaxation or adjustment, how does that work?

S.S - That was just a break on the royalties, so rather than paying the full amount we have a lesser royalty to pay.

C.B - And that's because you are trying a more innovative new technology and it recognises…

S.S - It's recognising that if you go out and do R and D work you're going to have incur costs that you wouldn't have to if you were just doing traditional conventional production. They want to encourage innovation in the province so if they give us a royalty break and we learn a thing or two, then we prove that the technology works for us so other people can probably follow in our footsteps. The Pembina project, the initial Pembina pilot, its 1/3 funding from Penn West, 1/3 funding from the Federal Government, and 1/3 funding from the provincial government. It's our understanding that the provincial and federal governments will not share the findings or results, other then basically saying "this looks likes it is working", "this looks like it is a good technology", they can't share (inaudible) the information as that would basically be giving away our trade secrets. For them they want their inside look into what's working and what is not working so they can suggest to the public: "is this actually an economic project?", "is this project actually feasible with a particular WTI price?" So governments want to be there right beside us to have a sense of whether or not it is an workable project, and we are hoping that they won't share too much of our knowledge with others because we're going to all the hassle.

C.B - So their role is more to spread the word that it is working, but 'we can't give you a lot of details'. In a nutshell is that right?

S.S - They're there to be of sort the cheerleader, if there is no success then they won't cheer anyone else on. But if it does work they will probably start promoting it to other companies. You are sitting on a lot of light oil if you have the ability to increase your recovery factor.

C.B - Is that kind of the same sort of idea with Weyburn, or was it…

S.S - No, as far as I know Weyburn received no government funding from the Canadian government. They did receive some assistance from the government of North Dakota, and the American federal government. The assistance wasn't to EnCana per se, but it went to the coal gasification plant in North Dakota to help on the capture side. So by reducing the cost of capture and providing some assistance on the pipeline, that is, making this assistance available up front they have helped the project get up and running. (10 second portion inaudible, speaking about whether or not government assistance was essential to the project…) I know that our people in the oil patch kind of feel that we need to have assistance up front, and for us before costs started ballooning we were pretty confident we could do it on our own, but now (inaudible).

C.B - I spoke to Malcolm Wilson, who's involved with the Weyburn project…

S.S - Is that from EnCana?

C.B - No, he works at the University of Regina. He's more on the…

S.S - Research side?

C.B - Yeah, I think he's more on the geological formation, how it's holding, how it's working, etc. His impression was that if you had a field as good as Weyburn (in terms of the way it holds and produces oil) then it could be profitable without incentives (but again, I don't know if that is his speciality, he's more on the

S.S - On the science side, not the money side?

C.B - Yeah (*I think so*). It was also interesting to hear that the scientists feel that it is geologically viable.

S.S - Looking at some of these questions here, some of them may require discussions with other members of our team (inaudible….). I'll answer them as well as I can.

C.B - (*With respect to the Pembina Cardium region, where is the* CO_2 *for the pilot project coming from?*)

S.S - Supplier is from a fairly close distance. Whereas with the Swan Hills project we are talking about a greater distance, from Medicine Hat, Lethbridge, etc. It's a bit more of trek but the trucking makes it uneconomical.

C.B - Ahh, so it's literally being trucked, not piped?

S.S - Yeah, for all of our pilots.

C.B - Oh, really?

S.S - Yeah, at Weyburn and Midale it's being piped, at Joffre it's being piped, but at Pembina and Swan Hills it's being trucked.

C.B - Okay, so that really reflects the pilot nature of those projects then?

S.S - Exactly.

C.B - Do you know what the purity of the CO_2 is (*before it is compressed*)?

S.S - It's very high. For most of the projects it has to be in excess of 98 or 99% pure, very, very high purity.

C.B - So that really reduces the number of (*potential*) sources, without them further increasing the purity right?

S.S - Yeah, a lot of the sources produce byproducts as well. It is a costly process to keep it pure, but if you could find a pure source most likely the costs would reflect this, in Canada the costs would be higher. I think in Canada the producers of pure CO_2 don't produce the quantities of CO_2 you would need. I guess the big advantage that a lot of American oil and gas producers have had is that they have large naturally occurring pure source of CO_2. So somebody like (Dunberry?) would be producing their oil with CO_2 from a natural underground source, and it's almost 100% pure.

C.B - That's kind of ironic though, they are taking CO_2 up from the ground to use to put it back in the ground.

S.S - Somewhere else, Yeah.

C.B - (*How much is currently being purchased annually?*)

S.S - I couldn't tell you that, but I think in one of our presentations we talked about how much we've requested to date, I'll just try to find that point here, one second…

C.B - I imagine it's not a huge amount if it's being trucked in though?

S.S - Well, with all of our different projects it's quite large. For all of our projects, just in the year 2006, we injected over 250 000 tonnes of CO_2.

C.B - And how much of that was recycled?

S.S - That's a very good question that I don't know the answer to. Again, recycling becomes more important as you have produced more of the oil in the formation. I think there is likely some recycle factor there, but I don't know.

C.B - Because the way I understand it is, that once a field becomes more mature you are up to almost 75% recycling or more.

S.S - I think the number I told you last time, the number somebody may have told me, when you are really full steam ahead, you can recycle as much 70%, I've never heard more then that, but perhaps it is possible.

C.B - (*I read that the initial tests have shown the site to provide good containment for the* CO_2. *What % of the net* CO_2 *injected do you expect to be sequestered over the next years 1000 years, 5000 years?)*

S.S - I have no idea.

C.B - Yeah, those are more on the geological side.

S.S - Somebody else here might be able to give you an answer, but I have no idea.

C.B - Okay, that's cool.

C.B - (*I read that you were in discussions with several industrial emitters to procure a large-scale* CO_2 *source for future commercial-scale flooding. Have you finalised a deal with a particular emitter)?*

S.S - No.

C.B - (*Can you comment on the type of industrial process, the cost range of the* CO_2*, the quantity to be purchased, or the concentration of this* CO_2*?)*

S.S - First of all, for our Pembina project we would eventually like to go to a 9 to 12 stage project, where we are brining on 1 or 2 phases a year. (Inaudible…) to get production from this field up to 35 000 – 40 000 barrels of light-medium oil per day. Right now I believe we are producing in the neighbourhood of 12 000 – 14 000. Basically the goal is bring on phases that add 6 000 – 8 000 barrels of light oil at a time. I think that in terms of quantity of CO_2, at peak production we would be looking at 250 – 300 million cubic feet per day. That would be when all phases are running so you wouldn't need all that at the start. What we've learned from talking to others who have used this technology is the more CO_2 the better. You put in more, you'll see a response faster, you'll recover more oil, so the more CO_2 we have the better.

C.B - So you need a real steady supplier with a large quantity and that's the problem?

S.S - Yeah, exactly.

C.B - (*I assume this will be transported via a pipeline, can you comment on any cost estimates for such a pipeline, the cost per/tonne of transporting this* CO_2*, etc?)*

S.S - I'm not sure what the transportation costs actually work out to. I think the pipe itself would be about 150 million, maybe?

S.S - I think for us, the more we spend on the pipeline, the smaller the transportation costs, and the cheaper the CO_2 will cost. If we take a bigger part of the pipe and are more involved in the capture side, people won't be able to charge us as much. I think for us that is important, knowing that we won't be at the mercy of transportation costs. Obviously as a producer you want to set up the field (*in a manner*) that your CO_2 costs will be economical in the long-term. I think our interest might be to be more involved in the infrastructure (*so we have a little control of the other side*)

C.B - (*Can you comment on the type of industrial process, the cost range of the* CO_2*, the quantity to be purchased, or the concentration of this* CO_2*?)*

S.S - For the concentration, it has to be very, very pure. In terms of cost, like we talked about yesterday between XX is where we would ideally like to be. Quantity, 250 – 300 million cubic feet per day (or more).

C.B - (*I assume it will be transported by pipeline*)

S.S - That's right.

C.B - (*I read in one of your reports that the Pembina Cardium fields have the potential for 150 - 400 million net incremental barrels of oil. When the reports use the term 'net', does this mean the figures have been adjusted for the extra energy required to capture and procure the* CO_2?)

S.S - Net is basically just indicating, net vs. gross. If we were to give you a gross number, the gross number would include any working interest partners that have an interest in the field. (Conversation regarding some Penn West reports, S.S walking C.B through various numbers, explanation of working interests, units lead operators, etc.). 'Net' basically means how much is net Penn West, after the other production goes to other operators in the area.

C.B - (*With Respect to the Joffre site, what price is being paid for the* CO_2*, and what is the concentration of this* CO_2*?)*

S.S - I don't know if I can get into that. I actually don't know.

C.B - That's quite all right, I've got a real good understanding of the numbers and prices from our discussion thus far.

C.B - (*How much net* CO_2 *has been injected to date, and how much is currently being purchased annually)*

S.S - A lot, I don't know, again somebody else may be able to get you that number.

C.B - (*What % of the net* CO_2 *injected do you expect to be sequestered over the next years, 1000 years, 5000 years?)*

S.S - I have no idea.

C.B - (*I read that the field has room for further expansion and surrounding pools could be flooded, can the existing* CO_2 *source produce enough* CO_2*, or would you have to find additional sources?)*

S.S - What I can do with Joffre is find you a presentation from Sept/Oct that was sort of our most thorough CO_2 presentation we've done to date, so I'll send you that.

C.B - Okay, cool, that would be great.

S.S - If you look at the first slide, the graph is 100% accurate. In 1977, the field was actually shut in. I don't know why that little squiggly line is there, but the field was not producing from 1977 to 1982.

C.B - So that should be a flat line running from (19)77 to that red arrow?

S.S - As far as I know the field was shut in, or maybe it was just not producing economically, we weren't losing money on it. It was producing such a small amount of oil, but I think they did shut it in and that's why I'm confused by the line there. What I've been told is that in (19)77 they shut the field in, because it was not producing enough oil. In (19)82 they started the injection of CO_2 and while it did spike up to 1200 barrels a day, what we typically say to investors is that we got up to that 800 barrel per day mark for a while, it then dropped to 600/day, back to 800, back to 600 and I think right now it's about 560 – 600. If you look at the table above, water-flood, 45% of the original oil in place was produced through water flood, so that was 18.3 million barrels. Tertiary recovery to date is 11%, so that is what has been recovered using CO_2 since (*19*)82.

C.B - So it's an incremental 4.5 million barrels just through using the CO_2, right?

S.S - Yes. And I think the 11% is the key % because we are aiming for CO_2 recovery of between 10 and 20% on any field that we would want to hit with CO_2.

C.B - Okay, so this is one is kind of on the lower end of where you would anticipate future fields?

S.S - Well, we're not done right.

C.B - Ahh, okay.

S.S - That's why we have alternate tertiary, we believe that based on the decline on the field chances are we will probably get out 16% using CO_2. The alternative tertiary figure is not 6.2 million barrels on top of the 4.5; we think the 4.5 will increase to 6.2 before we ever shut it in.

C.B - So there is another 1.7 that you are anticipating to recover. And all that CO_2 has been piped, no trucked in?

S.S - No, Joffre is an interesting case (and that's why I'm wishing that this other e-mail would go through.)

S.S - Let me let you go right now, I'll see if I can find those two slideshows and I'll send them to you. We can do some more follow up in a little while.

C.B - Sure, whenever is good for you, I just really appreciate you taking the time.

S.S - The two presentations I'm giving you, they are going to be very helpful. I'm sure you will probably have some more questions after this. If there are certain ones that are pressing, that you still really want to see if you can find the answers for, and I don't have the authority to help you, I will certainly help you get into touch with (?), but he's a hard guy to get a hold of. (Discussion of files sent back and forth)

C.B - Well, I'll let you go, because I can hear that you really need to get going, so thanks so much.

S.S - I'll get you two really good ones, honestly, I have a tonne of stuff that would be good for you but I don't want to over flow your mailbox. I could fill you mail box so I'll make sure to send you some good stuff.

C.B - Feel free to try. Thanks so much, and have a great day.

S.S - Thanks a lot, we'll talk again some time.

C.B - Sounds good, thank you, take care.

Appendix 1.3

Interview with Eric Beynon of the ICO2N (Integrated CO2 Network) December 14, 2007.

After chatting briefly about my program, Eric said it would be fine to tape record the interview and what follows is a transcription of this conversation. The style of transcription used was what Kvale would describe as a narrative one, thus removing any repetitions and pauses, as well as making the transcript more readable without altering the meaning or general sentiment of the interview. The reason for selecting this style was because the transcripts' intended use was to convey the general views of the interviewee (as opposed to being used for any linguistic or psychological analysis for example, which would generally require a precise verbatim transcription). Eric had been provided with a list of questions beforehand, so when these questions were not read allowed, they will be inserted in brackets with italics (*as such*).

E.B - So I've got your questions here in front of me, should we just walk through them?

C.B - Yeah, that sounds great, so the first question then: In your personal opinion, what do you think the potential for CCS is in Alberta?

E.B - Well I think it's huge, you've probably read our report, and I wouldn't say it is conservative on a build up because it is quite an ambitious project, but from an environmental stand point for what actually is possible…(inaudible.)…but 20 Mt by 2020 is totally feasible. To put that into perspective, that is probably about a quarter of the reductions of industrial emissions that the conservative government has put forward in its plan.

C.B - That's a big chunk.

E.B - Yeah, it's quite large.

C.B - And what would you say are the major hurdles in getting it implemented though?

E.B - Like any business decision it comes down to risks and costs. Right now it's expensive for a number of reasons, 1) the technology is new so the costs haven't come down yet, and at the same time, climate change policy is new and so the obligations costs are not high yet, so there is a disconnect there. Eventually the climate change obligation costs or penalties will rise to the point where it will drive CCS, so that (obligation) price will overlap the cost of CCS. Thus you don't want to do it in the near-term because that would hurt the economy if it's too abrupt, but they will need to fix that gap. There's also the element of risk because it's so new we don't know what the climate change policy will be, how the technology will play out, so a lot of those risks have to be addressed as well.

C.B - So moving on to my third question, and tied into that: What kind of pre-conditions would have to be in place to overcome some of those risks?

E.B - I think the biggest thing is regulation. That sets the barometer for substantive discussions between the companies, within government, and this will give you a lot more clarity on where we're heading.

C.B - So when you say that, you are looking towards the federal government, basically for an idea of what incentives/penalties, or price signals they will be sending on the costs of releasing carbon. Is that right?

E.B - Yeah, I would say that is fair. Alberta has its own climate change plan too, and at some point they will have to reconcile that. But yeah, exactly, so "What is the Plan?" I know a lot of companies are quite frustrated because they've been around the block; they've been through three different climate change plans in the last six years. Some of them have done stuff, and then been hurt for it, so there is a bit of hesitance to get going. So we'll see how regulation helps there.

C.B - That's what I've heard from a few people, they accept that there probably is going to be some regulation, they just want to know what it is so they can plan for it.

E.B - Exactly, and some certainty that it's going to be around for 5 – 10 years, that's the hardest thing. With investments in carbon capture and storage it takes 4 or 5 years from 'let's do it' (the time of investments) till it's actually operational. Those are big decisions based on what you think the environmental policy will be in the future, so clarity in that sense would really help.

C.B - Yeah, especially with these really big capital intensive projects there is a lot of money that has to come in the front end.

E.B - Yeah, exactly.

C.B - But given that, you still anticipate that within the next 5-15 years there might be a CO_2 pipeline network setup throughout Alberta?

E.B - I think it's inevitable. How we get there and when we get there is still up for debate. I think it's needed, at the end of the day I think we will be doing CCS and that's the way to do it. We may get there by a small project here, some projects there, a bunch of projects all over the place for a while…not all that efficient but it will get the ball rolling. Maybe in the end we'll wait till regulation drives us, so nothing happens till the price of an offset helps the cots.

C.B - Do you feel that public acceptance of CCS will have any affect on its implementation?

E.B - Yeah. I think it's gonna be a big issue. I think it's something that can and will be overcome. Well, overcome isn't the right word, but it's going to out there and there will be a big discussion about it. (Inaudible…). I know in Alberta there has been a lot of experience with sour gas, and other such things, whereas out here (Ontario) they don't have any experience with it so it tends to create a bit more concern. Just with the pure size of CCS and its presence within Canada will make sure that we deal with it.

C.B - If I can pinpoint what you're saying is that in a province such as Alberta it may not be too hard to convince the public, but in other areas of the country, on a federal level, it might be a little more difficult just with the different economies and what they are used to.

E.B - Yeah.

C.B - Okay, moving along here then. As far as you know, what are the Federal and Provincial governments' stances on it, and how this might affect the implementation of CCS?

E.B - Well, both are working on it. It's one of those things where it's a complicated issue and you have to wait for the planning to come together. Both have put a lot of time into it, the federal government has probably been working at it from a technology perspective for 10 years. Over the last few years I know that has really ramped up as well. It's coming together; how it's going to play out? Obviously these things become political issues at the end of the day too. How this plays in terms of politics, if it fits within a plan of one of the governments is the thing we are working on. I think it will come together eventually, but who knows.

C.B - Yeah…. I guess changing gears a little bit, how would you compare CCS to other CO_2 mitigation options that might be available?

E.B - We did some work on this actually, it's a complicated discussion when you get into that.

C.B - Yeah, it's quite a broad question I know.

E.B - Yeah. CCS has a huge volume. On the national roundtable on the environment and the economy, they did some work and concluded that CCS is the largest single reduction opportunity in Canada. Energy efficiency is altogether wider, but it is made up of wider but it's made up of all these tiny things and is actually quite difficult to achieve. It's incredibly important from a volume perspective. From a cost perspective right now, from the things we've seen it's sort of on par with wind, and some of the other alternatives out there. Obviously there are different drivers behind those, with wind it is more commercial, and with CCS it is more costs. It is important to maybe not look at it from a competitive standpoint, but rather the fact that if you sit back and look at Canada's GHG problem we're going to have to do all of them. So it's not necessarily one or the other, but it's more the potential for them all.

C.B - And following along that line, I guess there some that are more cost-effective in certain areas of the countries and others that are more cost-effective in others.

E.B - Exactly, I mean you can't really do hydro-power in Alberta or Saskatchewan.

C.B - Yeah, exactly. Whereas CCS could be much more applicable in Alberta then for example Ontario.

E. B - Yeah, exactly.

C.B - Okay, I'll move along to some of the questions on enhanced oil recovery. Could you comment on what the Alberta-wide (and/or Western Canada) potential is for EOR projects?

E.B - We did some work on this. I think the important thing is that there is huge potential for it and it is a great way to start CCS, because it drive some revenue. Two key things: 1) The revenue from enhanced oil recovery isn't going to be enough on it's own to drive CCS. You can see this now because nobody is doing it. 2) At the end of the day EOR is not going to be able to take all the CO_2 that's out there, so there is a supply demand issue, there will be much more supply then the EOR market needs. It's a tough one because they haven't really done a lot of EOR in Canada; you're looking at 8 – 15 Mt a year maybe.

C.B - Yeah, basically the only major project I have really come across is the Weyburn project in Saskatchewan.

E.B - Yeah, that is the only one.

C.B - In conjunction with EOR, how would you rank the high purity sources produced in the oil sands compared to other potential CO_2 streams they might use?

E.B - Well, you can always purify it, but that's another cost. A lot of the oil sands sources, the upgrader sources, are mid-range cost. If you were to retrofit a power plant that would be more expensive, but if you were to build a new power plant the cost would be cheaper, or in the same realm. The costs are something a lot of people are struggling with right now. Again, from what we've done its not looking at it so much from what is the cheapest cost point, but we step back and take a strategic viewpoint; 'What needs to be done?' You've got the industrial base (the oil sands, the oil and gas sector) from a strategic perspective you really need to undertake CCS there, just to enable the growth of that energy industry. You also have the power generation sector and we can undertake it there too, and the costs are very comparable between the two.

C.B - I think that brings me to my next question because when I saw you were going to be releasing your report I was quite happy with the timing of it. I was a little surprised because I had read through MIT's 2007 report 'the future of Coal,' as well as some reports from the Pembina Institute and they seemed to indicate slightly lower costs (or what they thought the cost would be) per tonne of carbon capture. I was wondering if you maybe walk me through that, and maybe explain how those numbers may be a little different. I know that you were working more with industry that is actually going to be doing it, and when I look at Pembina they are outside the box and trying to look in.

E. B - Pembina wasn't doing their own analysis, they were just taking their numbers from public sources, probably from the IPCC and MIT work. It's an issue of timing too; some of those bigger international works were from 2002-2003 data. When we actually updated our costs, from 2005 till 2007, there was a 25% increase, just because of the Alberta overheated environment, so I think that has a lot to do with it. Those numbers are up to date as of now, up to 2007. Also there are so many variables, what discount rate you use, etc. There are a million different variables on the back end, if you even change a couple of them that can change the cost. We did our best conservative estimates (actually, I guess you wouldn't say conservative) of what the costs would be, and that's what our estimates are.

C. B - I guess that makes a lot of sense, because that would fit with the MIT numbers. Their study wasn't done in the Alberta economy where the cost of labour and materials has just sky-rocketed

E. B - Yeah

C.B - It wasn't till I got your reply email that I realised you worked for Suncor as well, so I've added a few Suncor specific questions as well, but I don't know if you have the time or care to cover any of those. Of course I would be very interested to hear some of the replies if you do….

E. B - Actually I work independently, and mostly on ICON. The reason I have that Suncor e-mail is that Suncor is chairing ICON so it is through them that ICON is running. It's not an actual organisation, it's just an initiative. It is sort of one of those of funny nebulous things, where all these companies are working together, but it still needs to be housed in something that is formally registered, in this case Suncor.

C.B - Fair enough, I guess we can skip the Suncor questions then.

E.B - I'd be to happy answer some of them if you want?

C.B - Yeah, if you could address any of them that would be great.

E.B - Firebag, I'm no expert on that so we'll skip that one.

CB - (*It's my understanding that Suncor's oils sands refining and upgrading operations also require a great deal of natural gas, has Suncor considered alternative methods in the future, i.e. gasification using coke to reduce the reliance on natural gas?)*

E. B - Yeah, they use A LOT of natural gas, that is the main fuel source right now. That's the interesting thing; with respect to CCS lots of people are talking about gasification as a way to lower costs. When you split the power generation and industrial applications; power generation is using coal right now, so if you switched from a pulverized coal to a gasification plant you would still be using the same fuel source. Thus your emissions would be the same, except now you could capture the CO_2, and you could capture about 90% of it. This is a big decrease (in emissions) and you can actually directly apply that cost on a per tonne basis. When you are looking at the industrial base in Alberta, almost all of it, or a lot of it, is supplied by natural gas right now.

C.B - Is that those co-generation plants?

Yeah, the steam boilers and the upgraders (*to produce hydrogen*) are both driven by natural gas. If you are going to switch to a gasification plant you are switching from a relatively clean fuel in natural gas, to coke or coal, which is a dirtier fuel. As a result, the emissions will approximately double. The costs on a per tonne basis for capturing from the gasification plant is about half, so in the end your net costs are about the same. Thus it is difficult to always look at things on a per tonne basis.

C.B - Right. Okay, that was one of the things I was reading through and wondering, because if for instance natural gas prices started to increase substantially and companies may say "Should we take a long-term strategic view where we shift towards gasification units", then it would seem to me that it's even more important that a carbon capture network is either established or in the works so they chose to make a plant capture ready as opposed to a retrofit which is much more expensive down the line.

E.B - Yeah, and as the natural gas markets tighten and supply decreases it makes sense to use the natural gas for heating homes in North America. The oil sands sit on top of all this petroleum coke and dirty fuel, so they could use that, thus freeing up the natural gas. The problem with that is there are lots of fossil fuel emissions involved. If you could use that fuel and go to gasification, you have to capture it, and that's why having a CCS network in place is rather imperative.

C. B - Yeah, it's kinda the chicken before the egg argument there, because there is not a whole lot of incentive to set up these gasification systems if they don't know whether there will be a network.

E.B - Yeah, exactly. That's something we are all struggling with right now, trying to figure out.

C.B - This is something that Suncor and some of the other companies have considered, switching over to gasification?

E.B - Yeah, I think everyone is looking at it, but nobody is really doing it right now except for Nexen.

C.B - Yeah, I think I read about that one, and they are making their plant capture ready as well, is that right?

E.B - No, no they aren't

C.B - So it would have to be retro-fitted?

E.B - Yeah

C.B - Okay. But it is still cheaper to retrofit a gasification unit then it is to retrofit a normal unit, is that right?

E.B - I don't know about that, I wouldn't necessarily say that as no one has every done it.

C.B - Okay, I'm just looking through the rest of these Suncor questions here…

E.B - I think that the only other one that would be applicable to me would be number four.

C.B - (*One of the main drivers of CCS appears to be incorporating it with Enhanced Oil Recovery, does Suncor have any such existing or planned projects?)*

E.B - Just for a more general perspective, all the bigger companies got out of the more conventional oil because all the oil fields are declining. So there is actually a pretty clean split between the bigger players who are involved with the oil sands or natural gas production, and the folks who would be doing the enhanced oil recovery, largely the income trusts. There are a couple of companies with some interest in EOR (some of the bigger players) but for the most part the guys that are emitting the CO_2 are somewhat different than the EOR players.

C.B - Okay. If some of the bigger players were more interested in CO_2 EOR would that help speed things along (move towards a network), or is just that that is such a small area of business that is not something they are interested in?

E.B - Yeah. This is just speculation, but at the end of the day you have to remember that the companies are not in the business for CO_2, they are in the business for hydrocarbon production, and that is their primary business focus. So theoretically it would speed things along, but it's not a priority, nor a strategic investment.

C.B - I guess the potential oil revenue from EOR is just a drop in the bucket compared to their other oil sands operations.

E.B - Exactly.

C.B - Okay, I guess I'll go to my last few questions then.

E.B - Royalties?

C.B - Yeah. I was just back in Calgary last week and there was a lot of talk, on talk radio, etc, about the royalties so I've just been trying to ask all the different individuals for their take on it, their thoughts on the increase in royalties and such.

E.B - Yeah, it's been a hot topic. If you ask different people the consensus I've heard is that it hits the natural gas business a lot more than the oil business. I don't know the details of it all, but it's obviously one of those things where if you've got something and it gets taken away from you, people age going be annoyed.

C.B - Ha ha, yeah, they forget how much they may have in their hand…

E.B - Yeah, it doesn't matter how justified it is, people feel they have lost something so they are ticked off.

C.B - I think that's the best explanation I've heard so far, it's so true!

E.B - So yeah, it's a tough one, but I think it's settling down now. I think there is going to be a little fall out from what I've heard, especially with the natural gas drilling, mainly because it is all default drilling so it is risky and costs more. The price of natural gas is low so when the royalty hit it's not economical to drill those 5, 10 wells that don't result in anything. Thus I think a lot of people have closed up their drilling over the winter.

C.B - Okay, so it's the smaller natural gas (operators), it's not going to affect the larger oil sands operators?

E.B - No, I haven't heard anything major, but I'm no expert on that.

C.B - Are there any other individuals you would recommend I try to talk to regarding CCS and/or EOR?

E.B - I could send your questions and contact information to the companies that are on ICON here and I'd be able to target some of them that might be more open to it. (Discussion of what C.B should e-mail to E.B). Feel free if you have anymore questions, let me know.

C.B - Are there any other points you would like to expand on, or perhaps any questions you may have for me?

E.B - Have you heard much about the oil sands in Europe?

(Interview wraps up with a discussion about how the oil sands are perceived in Europe, as well as the recent Husky announcement which made front page news will Eric was in the UK.)

<u>Permission to record and Transcribe the Interview:</u>

With your consent I would like to tape record the interview so that I can transcribe the interview and include the transcriptions in the appendices of my thesis. The knowledge gained through the interview will generally be summarized in the body of the thesis, however selected quotes, facts and/or figures may also appear in the main thesis (again, with your consent). If you would prefer to keep any information confidential, whether it be your name, your company, a particular project, or any project specific information I will of course respect that and not include it in my thesis or any appendices. Once I have transcribed the interview I would be happy to send you a copy to ensure that I have not made any errors and that you are comfortable with it as is before it is included in the appendices.

Appendix 1.4

Dec 14th interview with Dr. Malcolm Wilson, an energy expert at the University of Regina and the director of CO_2 management at the Energy Innovation Network.

After chatting briefly about my program, Dr. Wilson said it would be fine to tape record the interview and what follows is a transcription of this conversation. The style of transcription used was what Kvale would describe as a narrative one, thus removing any repetitions and pauses, as well as making the transcript more readable without altering the meaning or general sentiment of the interview. The reason for selecting this style was because the transcripts' intended use was to convey the general views of the interviewee (as opposed to being used for any linguistic or psychological analysis for example, which would generally require a precise verbatim transcription).

C.B - One of my first questions is just in your personal opinion, what do you think the potential for carbon capture and sequestration is in Alberta and/or Western Canada?

M.W - I think fundamentally it is pretty much unlimited, in general sense, there is a huge capacity for geological storage in Western Canada. We are looking primarily at Alberta and across the Southern part of Saskatchewan into what is generally called the Western Canadian Sedimentary Basin, and potentially up into the north-eastern portion of British Columbia as well. If we can capture it, there is a huge potential to store it in the ground in that area.

C.B - What would you see as the major hurdles to implementing CCS in Alberta and/or Western Canada?

M.W - The main hurdles are: 1) Getting some really concrete direction from government as to what is going to happen, and (*2*) the other hurdle is of course the economics. If you can capture the CO_2 relatively cheaply and sell it for EOR (Weyburn style) then that's great. It becomes a potentially even a profit centre, Dakota gasification is actually making (I believe) quite a bit of money on selling that CO_2. Firstly, the opportunities for EOR are not inexhaustible so we have quite a limited amount of EOR versus potentially the amount of CO_2. Secondly you have an issue of how much people are willing to pay versus cost of capture. So whatever happens, sooner or later, it becomes a cost issue. So without having solid policy direction that says "you will face costs if you don't do it", then it is easier not to do it. Even policies saying for example $15/tonne is not really a great encouragement for actually doing anything as it is cheaper to just pay the bill. When you are looking at $30,40,50 to capture and store CO_2, $15 looks pretty good.

C.B - So that is the cost range as you see it right now for carbon capture within Alberta/Western Canada, $30 is the minimum, and up to $40 and $50, is that right?

M.W - Yeah, if you incorporate the full cycle, you are probably looking at, at the moment, in the $30-$40 range for capture, and then depending on how far you have to transport it you are probably looking at $5 - $10, maybe it's a little more for the transport, geological storage, and monitoring.

C.B - Now to what extent, if any, do you think the public acceptance of this technology (CCS), with or without EOR, will affect its implementation in the short term?

M.W - Sorry, you said public acceptance?

C.B - Yeah, I was speaking to someone else this morning who was based out of Toronto, and he felt that perhaps when people first hear about it out east they may be a bit more sceptical, whereas people in Alberta are quite used to having pipelines and oil and gas activities going on in the province, they might be more open to it.

M.W - Yeah, if you look at the Weyburn area, the people in that area are very accepting of CO_2 enhanced oil recovery, because they recognise the jobs, the farmers like to have that activity on their land because it is a guaranteed source of income, and all that type of thing. I believe people in oil producing areas generally view CO_2 as “it’s like water, it’s like chemical floods” It’s another solvent that’s going into the ground. But if you start to move beyond oil producing areas, where people are not used to it, and you start looking at Weyburn putting away 2 million tonnes of CO_2 a year, and you start looking at projects that are potentially putting away 10 million tonnes of CO_2 a year, people start thinking of the volumes in the subsurface, in particular the aerial extent over which that CO_2 is going to spread. Then I think you are going to have quite a different reaction, and much more of a demand to demonstrate the acceptability, the integrity, the safety (whatever word you want to use), of that storage. I think that is going to occur in Alberta, in Saskatchewan, in much the same way as in Ontario or Nova Scotia. The onus is going to be on us to make sure we’ve done our homework.

C.B - I had a few more general questions, and then some more Weyburn specific questions here. One with respect to the Federal and Provincial governments’ stances on CCS and how will this affect it’s implementation, from your point of view, how do they regard it?

M.W - In talking to both, there is a recognition at the federal and provincial level that this is a technology that provides one of the many possible solutions, it’s not the only solution, but it’s one of many that we need to be moving ahead with. There is a fundamental agreement as to moving ahead with it. There is inevitably the concerns around jurisdiction; who has powers to do what, and who regulates this kind of activity. As we move away from enhanced oil recovery, and more into geological storage, and getting approval and recognition for CO_2 stored and things like that, you are getting much more into that grey area between federal and provincial regulation and constitutional authority. There is a bit of friction there on occasion, but in talking to them my sense is that there is a lot of goodwill in terms of trying to get this resolved in a way that meets everybody’s needs.

C.B - That’s nice to hear. With respect to enhanced oil recovery can you comment on what the Alberta-wide or Western Canadian potential is for such projects? I’ve read varying numbers in terms of how much incremental oil could be recovered and how much potential storage capacity there is within such reservoirs.

M.W - Yeah, you look at some of the screening studies and numbers are ranging in the 400 million tonnes of CO_2 – 600 million tonnes for enhanced oil recovery. I think those are fundamentally the better reservoirs. It all depends on the value of CO_2 because whenever you put CO_2 into an oil reservoir (particularly the lighter and medium crude) you are always going to get something out. So the potential capacity is a lot higher than that, but that is kind of an immediate “what might be the good opportunities that are out there.” If the value of CO_2 goes up, then we’ll see more opening up. What’s the limit, I really don’t know what the answer is, double, triple? Certainly if we are using fully depleted (or what me might consider to be fully depleted) oil reservoirs then it goes up a fair amount, but you will still potentially get some oil out, so is it EOR or is it storage?

C.B - I see what you mean. I am trying to tie this into the oil sands a bit, how would you rank the CO_2 (in terms of purity, concentrations and such) that is coming from the oil sands productions? I’m looking whether down the line they can capture this CO_2 and send it down to the EOR areas of

Alberta for example. How does it compare to CO_2 from an industrial plant, such as fertiliser plant or the CO_2 that I believe is coming up from North Dakota?

M.W - The problem with the tar sands (or anywhere else for that matter) is that you have a whole range of technologies coming up with a whole range of purities. So the process at Dakota gasification gives you a very high purity of CO_2, and it is in fact bone-dry CO_2, so it is ready right there and then to be compressed and put in a pipeline. A lot of the fertiliser plants, some of the hydrogen plants up in the tar sand, the older technology actually tends to be fairly pure.

C.B - Yeah, I found that a little ironic

M.W - And the newer technologies, the Pressure Swing Absorption Technologies, (are less pure) then the older technologies, the chemical processes, physical solvents…

C.B - Is that the amines?

M.W - Yeah, and there are some other solvents that operate just as well, the Benfield type, Selexol, or whatever they are using. Those type of systems produce a pure stream of CO_2, and that's good. Dehydrate it, compress it, and stick it in a pipeline. The incremental costs are relatively low. Pressure Swing (if I understand it correctly) you're dropping to about 40-50% CO_2 purity. The higher the purity of the CO_2, the lower the cost of completing the process of getting it up to whatever standard you want to use for putting it into the pipeline.

C.B - The sense I was getting was that if these oil sands producers are starting to switch away from these high purity sources, they need some indication whether this network is going to be established soon, and some incentive to capitalise on that, especially with all these new projects coming on line.

M.W - Oh absolutely, and you continue to move down that pathway: If you are using natural gas for producing steam, a nature gas boiler is probably putting out a CO_2 stream with about 10% purity. If you are running it through a gas turbine, and then capturing the heat to produce steam, then your CO_2 purity drops to about 4%. Each time you see this drop in purity, the cost of capture goes up substantially. It is a lot higher to capture 4% then it is 8%, or 16%, or 40%, or whatever. It's going to be cheaper to capture from a coal fired power plant then a natural gas turbine. But the technologies in Fort McMurray and surrounding area are largely naturally gas based right now. Then you look at Nexen, and they are going to be burning a CO rich stream, which in a turbine or a boiler, because your steam has a higher carbon ratio, the CO_2 concentration of the flue gas is going to go up and the ease of capture is going to be improved/

C.B - Is that the coke-gasification facility?

M.W - Yeah.

C.B - Okay, if I understand it correctly (and I haven't been able to speak directly with anybody from their firm, but I have spoken to someone else), it's not going to be a capture ready facility?

M.W - No (*in agreement*)

C.B - If they are going to do it, it's going to have to be retrofitted, so that's one of those things where (and I realise it's always easy to say what if), but if five years ago they knew that a CO_2 pipeline would be set up, then perhaps that would be capture ready facility, because the retrofitting is fairly expensive isn't it?

M. W - Well, moderately, but the cost of retrofitting has come down quite a bit. The issue with 'can you make it capture ready' is that when Nexen made those designs I don't think that they could. Because that would have meant putting in facilities that would allow them to do a gas shift reaction on the CO, to produce hydrogen and carbon dioxide. And that is a very expensive piece of capital to have sitting doing nothing for 10 years. You could leave the room to put that into the stream, but basically since some of the hydrogen went to the upgrading, and the CO rich stream (which still contains some hydrogen) goes into the turbines or boilers or whatever, to produce the electricity. There is currently no such thing as a hydrogen turbine (certainly not at that scale). So they did not have that option; they always knew that if they had to do something in the future, they would have to retrofit.

C.B - Okay. Because I was reading the MIT Future of Coal study which discussed the various prices for retrofitting, the price of leaving space for a retrofit, the different costs, etc, and that seemed to be the same that they were saying, namely that because it is such an expensive capital outlay it is better to wait and see, particularly with the uncertainty regarding regulation.

M.W - Yeah, any economic analysis will tell you that if you have to put economic capital in up front and not use it, then it is a waste of money. Whereas the retrofitting of post-combustion capture is a debate we are really heavily into here right now. Retrofitting is really an issue of space.

C.B - Okay...

M.W - Because tying into a power plant is a relatively simple exercise (that's a bit of an over simplification because if you take off a lot of steam, or regeneration of your amine, then you have some stranded capital in place in the form of your low pressure turbine that are operating sub-optimally, or not operating at all.) So there is an issue there because conversely if you delayed your capital investment then you would have full use of your turbines for those 10 years. Thus it is a complex decision that has to be made.

C.B - Especially without any regulation in place yet….

M.W - Yeah, and that's the problem, they can't do adequate planning, even in terms of really fully understanding from an economic perspective what capture ready is (technically we know what capture ready is), but economically we really don't understand it because we don't know how long it is before you have to implement whatever levels.

C.B - Okay, thanks. I do have some more Weyburn specific questions I was hoping you could help me out with. With respect to the purchase of CO_2, was there a certain amount that had to be purchased per month? Did a certain amount have to be purchased per month (I read that in 2004 it was about 5 500 tonnes per day), was this figure flexible depending on the needs of the fields?

M.W - I think the original contract was a fairly rigid 'take or pay contract'and was set at 100 million standard cubic feet/day (which is somewhere in that that 5000 – 5500 tonnes per day range). I think that Pan Canadian (who signed that contract in the first place) was always looking at the upside, they obviously had some downside concerns, but they were willing to take that penalty because otherwise it was not going to be cost-effective to take on that contract. But the thing about that contract was that it was a declining supply contract, so it wasn't 5000 tonnes a day for 15 years, it was 5000 tonnes for some period of time, and declined to 3000 tonnes after 15 years.

C.B - If I understand it correctly that's because as you flood the fields with CO_2 there is more CO_2 that comes up near the end, it gets recycled?

M.W - Yeah, that's right. The original contract called for 20 million tonnes of purchase, but that was a total of 43 million tonnes of injection, so there is a lot of recycling in the system.

C.B - Is there a temporary storage facility on site?

M.W - No, there isn't. This has been one of those debates that has been ongoing for some time, is do you put into place storage so you can balance out the supply, or does the oil field accept the fact that the system is going to be down periodically. And basically, for virtually all of them it is too expensive to go to storage, and they want as much CO_2 as they can get early in the process, so they are willing to accept the fact that they have to be down periodically.

C.B - With respect to the pipeline from North Dakota, what is the maximum capacity of this pipeline?

M.W - The first part of the pipeline that runs up somewhere close to the border is 14 inches, and it has a capacity of at least 12 500 tonnes a day of CO_2. The pipeline from Tioga in North Dakota up to Weyburn is 12 inch, and is currently flowing 7 500 tonnes/day, with at least 1000 tonnes spare capacity, maybe more.

C.B - The reason I ask is because I was curious if you know what the cost of transportation per tonne of CO_2 is, per 100 km for example? Or is that something they have kept to themselves?

M.W - They have kept that to themselves. I believe it cost them around 120 million to put in the pipeline and original compressors for the CO_2. I have a rough idea, we are talking about $US18/tonne delivered to Weyburn. How much of that is compression, how much of that is pipelining, and how much is profit I don't know, but I'm guessing that the pipelining costs (given the volumes) are probably at the lower end of the range, roughly $1 /tonne/100 km, maybe a little higher than that. I kind of expect we are at the low end given that this is one of the cheapest places in the world to put in pipelines.

C.B - So when you say roughly $18, that's the price you figure Weyburn is paying, or is that the total cost including capital, etc?

M.W - Based on the contracts, the original contracts, that is the operating and capital amortisation, and profit for Dakota Gasification. So roughly speaking US$18/tonne covers all those costs, so at the end of the 15 year period, the capital would be fully amortised over that 20 million tonnes.

C.B - Okay, so it would be safe to say that the Weyburn field is paying less than $20/tonne for the CO_2?

M.W - Yup.

C.B - I was reading through a Penn West publication (which I understand has an interest in the Weyburn field)….

M.W - Yeah, they are the second biggest owner in the Weyburn field…

C.B - Yeah, and they said that they had operating costs were around \$6.60 and current netbacks were over \$40 per barrel; could you comment on how these numbers compare to other potential EOR projects, because those are pretty good, to me that seemed to be quite a low operating cost for an EOR project?

M.W - Yeah, it depends what they mean by operating costs. I find it hard to believe that that includes the cost of CO_2.

C.B - You know, interestingly enough, it did say it did. It did admit that this was one of the lower operating costs….

M.W - Let's try to put that into some sort of context and I'll think out loud here: Every tonne of CO_2 they purchase is costing them around \$18. That produces on an instantaneous basis about 3 barrels of oil, so on a new CO_2 basis it is costing them around \$6/ barrel. They are recycling (injecting) now well over 6 000 tonnes, up till the new supply coming on they were injecting 5 000 tonnes a day of new CO_2, and about 2000-2500 a day of recycled CO_2. The recycled is probably costing them about half, lets say for the sake of argument about \$10/tonne. So the oil produced from that is roughly \$3 of CO_2 / barrel, so if you do some blending, CO_2 costs on an instantaneous basis are around \$5.50. Usually the field operating costs for lifting oil and for processing it for export (getting rid of water, etc) the numbers used to be around 4.50/barrel, latest numbers from ZIFF may in some instances actually be doubling that, because of higher capital costs, higher operating costs, etc. So if they just look at the operating costs from a CO_2 costs basis, then that \$6.50 sounds reasonable.

C.B - So it sounds as if it is missing one of the two factors?

M.W - I kind of worry that they might be. Now again, the other interesting thing is that when an oil well is flowing well with CO_2 they are often getting what is called a 'gas lift', where the CO_2 is providing the driving force to move the oil up the well as the CO_2 comes out in the solution.

C.B - Thus reducing the operating costs?

M.W - They turn the pumps off. So there is no operating of the pump and this reduces their cost of producing oil. So while not having any of the numbers, \$6.50 sounds a little low to me but it's not inconceivable with where Weyburn is today, their lifting costs dropping right off, economies of scale with 30 000 barrels/day (instead of 10 000/day)…maybe? That would be great if it were.

C.B - That's pretty impressive.

M.W - That's a very impressive number.

C.B - We were talking earlier about the total capacity for EOR in Western Canada/Alberta, now how many fields, or how large are the fields, etc, do you think could be in this price range, perhaps not quite that low, but within that ballpark, in terms of operating costs? Is Weyburn just that much better than all the other fields, or are there many fields that are comparable to it in your opinion? I know it's hard to compare or say before they have been…

M.W - Recognising that this is a personal opinion, my feeling is that Weyburn is probably the best, or close to the best field in Western Canada, because of the geometry of the field, and the field is very amenable to gravity override of the CO_2. Now there are bigger fields like Pembina, where Penn West is operating….

C.B - Yeah, I spoke to some them yesterday…

M.W - The trouble with Pembina is that there is so much heterogeneity in the field that it is going to be difficult to control the CO_2 floods to the same extent that you can with Weyburn. There are going to be really good areas in Pembina, but there will also be absolutely atrocious areas within Pembina. They'll get good results in the good areas and get lousy results in the poor areas. As a single field, that portion that EnCana is flooding (*referring to Weyburn field?*) is probably one of the best you can find.

C.B - I just wanted to be very careful not to take the Weyburn numbers and extrapolate and say that (*all EOR fields should expect similar results*)….

M.W - No, absolutely not. Even fields in South-eastern Saskatchewan, Midale is not as good as Weyburn, and is the same field. If you move to Steelman, it's similarly not as good as Midale and Weyburn. It's potentially amenable, but it's not going to give you quite the same results.

C.B - Right, so you are not going to see those netbacks of $40 that they are talking about.

M.W - No (*in agreement*).

C.B - Now I have some fairly specific questions so bare with me. I think it was page 172 of the Weyburn Project Summary Report 2000 – 2004…

M.W - Uh, huh.

C.B - It had to do with the demonstration case regarding the economics of the Weyburn project and how they are simulated. I just wanted to make sure I have understood the numbers correctly. It said that incremental oil recovery from 2001-2033 is estimated to be around 21 million cubic meters (133 million barrels)

M.W - Uh, huh.

C.B - 25 Mt of CO_2 is estimated to be purchased over that time, is that right?

M.W – 20?

C.B - They have it listed as 25, 'M' 'T'?

M.W - Yeah, million tonnes.

C.B - Now they had listed the cost of CO_2 to be C$29.85/tonne, but from what we were talking about earlier, it sounds like it was a little lower?

M.W - Oh, yeah…

C.B - Now these are just the numbers they used in their simulation I believe…

M.W - Yeah, the original PanCanadian proposal was 20 million tonnes (*of purchased* CO_2*)* and about 130 million barrels of oil over the lifecycle. In that report we were not using PanCanadian/EnCana's internal simulation. There was a separate set of simulations run out of the

Alberta Research Council so the numbers were slightly different. They are not that far out, but the other thing you have to remember is that we were talking $18 US a tonne, and the exchange rate at the time was running at 62-65 cents (whatever it was)…

C.B - So it is back to around that C$30 mark?

M.W - So those numbers have been transposed into Canadian dollars at that time and so today that value has dropped.

C.B - It listed a total storage cost of C$1.32 billion?

M.W - Yeah, and that's not an unreasonable cost, basically PanCanadian's original estimates were around $1.2 billion for new field investment and purchasing CO_2. That's escalated, so you could even add some more to that right now because of the cost of drilling wells and so on. But those are not bad numbers.

C.B - When I started crunching the numbers, according to the simulations, at a price of C$30.15 a barrel, the EOR project would generate an internal rate of return of about 10%, according to those simulations. If that's accurate, then that would lead me to conclude that similar EOR sites would generate an internal rate of return of 10% or greater if oil prices were above $30 a barrel and CO_2 could be acquired for less then $30/tonne. Is that a correct (*conclusion)*?

M.W - Yeah, that sounds reasonable. In 2004 there was a paper put out by British Petroleum and they basically were using numbers that said if West Texas oil was selling at $21, $25 a barrel, then you could afford to pay 16.40 (somewhere in the US$16-17 range) for CO_2, and come up with an internal rate of return of 20% or so on those projects. So, yeah, your numbers are pretty reasonable.

C.B - It seems that there are substantial profits to be made if oil continues to be even near the price it's at now because it doesn't seem to me that the cost of acquiring CO_2 is likely to go up that much, and could in fact go down depending on…

M.W - There are a number of issues there: One is that as the price of oil goes up, the price of development goes up, the lifting costs go up, all of your infield costs go up as well, so it is not a direct comparison. Just because the price of oil goes up to $50 doesn't mean you can pay $40 per tonne of CO_2 instead of $30, it's not quite linear, so it almost has to be done on a price sensitivity basis. But fundamentally, when I was recently down a while ago at a SPE (Society of Petroleum Engineers) meeting, some of the numbers being bandied around were: as oil is in the $50-60 range (we weren't up to $80 then), the feeling was that prices around $35/tonne for CO_2 were about right. So you can escalate that up a bit, but it's not linear. If you put oil up $20, you don't necessarily put CO_2 up $20, it may be $15, or something like that.

C.B - But it would seem to say that there is a lot of potential for EOR, even without extra government incentives or a price on CO_2, there is already a profit to be made there.

M.W - Oh, absolutely. The other thing of course again (and you said it yourself) is that we have to be careful not to extrapolate from Weyburn without thinking about what we're saying. On an instantaneous basis Weyburn is getting about 3 barrels of oil per tonne of CO_2 injected. If you go to another field, I don't know what the numbers will be for Steelman for example, but that could be 2, or 2.5 barrels per tonne of CO_2 injected. Weyburn on a lifecycle basis is 6.3 barrels per tonne of CO_2 purchased. Maybe Steelman is 4.5 – 5 barrels on a lifecycle basis. Again you have to balance your economics out on your expected rate of recovery per injected tonne. We could play with the numbers, but it really comes down to doing a field by field economic analysis, or simulations.

C.B - For the purpose of my study I don't need really accurate (*precise*) numbers, it is just to get a general sense of what is profitable, what's not, what's the range, so that is a great answer for me, thank you.

C.B - The demonstration case went on to look at the 2034 – 2053 time span: with incremental oil recovery estimated to be about 44 million barrels, 26 Mt of more CO_2 estimated to be purchased, and the costs the same. It said they needed a CO_2 credit of about C$8/tonne to get them back up to that an internal rate of return of 11%. That's starting in 2034, so that's assuming the can get some kind of price on CO_2 of a minimum of $8/tonne by then.

M.W - Yeah.

C.B - That to me again sounded pretty reasonable.

M.W - Now again, the thing there is that it was calculated with lower oil prices.

C.B - Yeah, exactly.

M.W - Secondly, the original flood pattern covered about half of the geographic area of the field, but that was probably 60% or more of the oil. As you move out from there, you are moving into less amenable reservoir, so your rate of return, in terms of the amount of oil you get back per injected tonne, (*goes down*). What it was trying to do was project that out to see what would be the ultimate capacity, and what would be the requirement for subsidy at those oil prices, whether that's tax credits, emission credits, or whatever it happens to be, that you would need in order to retain enough profitability in the field.

C.B - Now again to me that seems like reasonable numbers….

M.W - Yeah, EnCana has already expanded the field based on newer oil prices.

C.B - Yeah, because even without the $8 credit, based on the numbers you are telling me (how much oil they are getting per tonne, etc), roughly anything over $50, they don't even need that credit.

M.W - Yeah, exactly.

C.B - Okay, those are my Weyburn questions. The only other questions are really general. When I was back in Calgary last week everyone was talking about the issue of royalties and the recent plans to increase them (it's a really hot topic), and I was curious based on the work you have done, should there be different incentive scheme for enhanced oil recovery? Essentially you are taking CO_2, putting it in the ground (a good thing), the royalties are higher on conventional oil (at least in Alberta) as opposed to the oil sands, so it seems to me it's really a win-win (*situation*) for the government so perhaps they should provide some incentive for more enhanced oil recovery.

M.W - Again, I can't really comment on Alberta

C.B - Yeah, sorry, I forget that.

M.W - In Saskatchewan they set up a one-off set of fiscal incentives and royalty incentives for Weyburn, and I believe these have been mostly enshrined in regulation. But basically the government reduces the royalties to almost nothing….

C.B - Oh really?

M.W - …during the payout period (so in other words, the costly period), and once you hit payout, then royalties jump back up to the conventional rate, 30% of gross, or 10% of net, or whatever it is.

C.B - That sounds very similar to the royalty regime with respect to the oil sands…

M.W - Yeah.

C.B - It's 1% till everything is paid back and then it's 20 some percent. This is what has caused this huge (*recent investment*)…

M.W - Basically what that is, is a recognition of these high upfront costs, and that chops the payback period quite a bit. In fact Saskatchewan with PanCanadian allowed them to start charging the royalties at a low rate 18 months before the first injection of CO_2. Thus recognising the several years of field development ahead of the first injection of CO_2 (during which the company was putting out money). So the government said "Okay, that's fine, we'll share that risk". What that does is, it increases the rate at which you pay of the project, so it's that much sooner that we start bouncing back up to high royalties, and we get our share then.

C.B - Yeah, I understand. Just from what I've been learning about the oil sands, that has been of the big drivers for more and more investment, because they didn't quite want to get to the point where they had all their investment paid off yet.

M.W - Precisely, and that's what's happening at Weyburn. And of course the other thing is that the royalty curves are sensitive to oil prices and also the cost of producing oil. So because EOR projects are inherently more expensive, the royalty curves are more sensitive to that.

C.B - When you say 'inherently more expensive', that is compared to conventional oil, not compared to the oil sands for example, right?

M.W - Oh, yeah, yeah.

C.B - Yeah, I just wanted to make sure. Well, thank you so much, are there any other points you'd like to expand on, or questions you perhaps have for me, or anything we've (*discussed*).

M.W - No, I don't think so. It will be interesting to see what you've come up with when you get your thesis done, or any papers that come out of it.

C.B - Yeah, and I will most definitely send you a copy of the transcription of the interview when it's done. I have to say thanks so much, it's been very difficult when I've been talking to the people from private industry to pin down some numbers (they don't want to be held to anything, it's very secretive, etc). So thanks very much for your time, and have a great weekend.

M.W - No problem, Have nice Christmas

C.B - Yeah you too, thank you.

<u>Permission to record and Transcribe the Interview:</u>

With your consent I would like to tape record the interview so that I can transcribe the interview and include the transcriptions in the appendices of my thesis. The knowledge gained through the interview will generally just be summarized in the body of the thesis, however selected quotes, facts and/or figures may also appear in the main thesis (again, with your consent). If you would prefer to keep any information confidential, whether it be your name, your company, a particular project, or any project specific information I will of course respect that and not include it in my thesis or any appendices. Once I have transcribed the interview I would be happy to send you a copy to ensure that I have not made any errors and that you are comfortable with it as is before it is included in the appendices.

<u>Post Interview thoughts</u>

Dr Wilson had not had a chance to review the questions beforehand and as a result (relative to the other interviews) this was more conversationalist in nature as I found myself conversing a little more, posing additional follow-up questions, and not simply following the questions as I did in my first interview with Dr Bachu.