Learning from international CCS policy and regulatory developments: Insights from Alberta

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1 Executive Summary

Despite policies and measures to accelerate CCS in the European Union, no fully integrated demonstration project has reached a favourable final investment decision. Other parts of the world are also experiencing difficulties in accelerating CCS. The province of Alberta in Canada, has adopted an aggressive approach to supporting CCS projects, with two flagship CCS projects having reached a final investment decision, and currently in development.

The overarching objective of this report is to assess the prevailing CCS policy and regulatory frameworks which are able to support the successful development of fully integrated CCS demonstration projects in Alberta. Particular emphasis is placed on the structure of the project financing, particularly the level of government support, private investment and revenue streams. In addition, certain elements of the Albertan regulatory framework for CCS, specifically the liability risks faced by project operators, and the requirements for financial security for the long-term stewardship of storage sites, are reviewed.

There are a number of key characteristics that distinguish the project selection procedure and the CCS funding programme operational in Alberta, from CCS funding support programmes in the EU, namely the European Energy Programme for Recovery and the New Entrants Reserve 300:

- The overall total available funds committed per project in Alberta is greater than what has been made available in the EU.
- A maximum funding rate of 75% of relevant incremental costs is permitted in Alberta, compared to 50% of the relevant costs permitted in the EU's NER300.
- Alberta's CCS funding programme allows for 40% funding to be provided during the construction phase, whereas the NER300 utilises an annual performance payment, requiring the potential project operator to risk significant capital investment.
- The type of CCS projects chosen in Alberta, high-purity CO_2 sources from hydrogen production, are technically less challenging and less energy intensive than the projects chosen for the EEPR, which involve first-of-a-kind post combustion and oxyfuel power generation installations.

Regarding the regulatory framework for CCS, it cannot be concluded that either the Albertan or European framework places greater demands on the operator in terms of financial security requirements or exposure to liability. The Albertan RFA steering committee recommends a minimum 10 year closure period prior to the transfer of all liabilities to the government, whereas the EU Directive on the geological storage of CO_2 states a minimum of 20 years, but tolerates Member State discretion to shorten this period. The certainty of having a 10 year period could be considered an advantage in terms of risk management and investor confidence.

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Acknowledgements

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2 Abbreviations

ACCSDC	Alberta Carbon Capture and Storage Development Council
ACTL	Alberta Carbon Trunk Line
AER	Alberta Energy Regulator
AOSP	Athabasca Oil Sands Project
CCEM	Climate Change Emission Management Fund
CCS	Carbon capture and storage
CS	Carbon sequestration
EEPR	European Energy Programme for Recovery
EOR	Enhanced oil recovery
EPC	Emission Performance Credit
EPEA	Albertan Environmental Protection and Enhancement Act
EU	European Union
GDP	Gross domestic product
GHG	Greenhouse gas
GW	Gigawatt
LCA	Life cycle analysis
LCFS	Low Carbon Fuel Standard
MJ	Mega joule
MMA	Albertan Mines and Minerals Act
MMV	Monitoring measurement and verification
Mt	Megatonne
NER	New Entrants Reserve
OGCA	Alberta Oil and Gas Conservation Act
PCSF	Post Closure Stewardship Fund
RFA	Alberta Regulatory Framework Assessment
SCO	Synthetic crude oil
SGER	Albertan Specified Gas Emitters Regulation
SRA	Alberta Surface Rights Act
TW	Terrawatt
WtW	Well-to-wheel

3 Introduction

Despite policies and measures to accelerate CCS in the European Union, no fully integrated demonstration project has reached a favourable final investment decision. With an original goal of 12 demonstrations projects by 2015, a combination of a weak CO_2 price, the economic recession and seemingly insufficient Member State support, has seen many of the planned CCS projects either cancelled or delayed indefinitely. The EU funding strategy for the deployment of demonstration projects, and excessive regulatory demands regarding CO_2 storage, can be considered as key contributing factors to this outcome.

Other parts of the world are also experiencing difficulties in accelerating CCS, with the majority of CO_2 injection activities commencing in recent years relating primarily to enhanced oil recovery projects in the United States, whereby the storage of CO_2 from the purposes of preventing climate change is really a by-product of an industrial activity. Despite this, the province of Alberta in Canada, has adopted an aggressive approach to supporting CCS projects, with two flagship CCS projects having reached a final investment decision, and currently in development. These two projects are estimated to commence injection between 2015 and 2016.

3.1 Research objective

The overarching objective of this report is to assess the prevailing CCS policy and regulatory frameworks which are able to support the successful development of fully integrated CCS demonstration projects in Alberta. Particular emphasis is placed on the structure of the project financing, particularly the level of government support, private investment and revenue streams. In addition, certain elements of the Albertan regulatory framework for CCS, specifically the liability risks faced by project operators, and the requirements for financial security for the long-term stewardship of storage sites, are reviewed. The rationale for this assessment is to evaluate whether certain approaches to the issues mentioned above, could provide valuable insights for European policy makers on devising regulatory and policy provisions to successfully demonstrate CCS in the EU.

3.2 Reader guide

Section 4 of this report provides the necessary background information of the energy mix and associated emissions of Alberta, and introduces the provinces climate and economic development goals. Section 5 outlines greenhouse gas abatement policy in operation in Alberta and its relevance for CCS projects. Section 6 documents the political actions taken by the provincial government to create an enabling environment for public and private investment in CCS. The project selection procedure and a brief description of the two CCS projects under development in the province are provided in section 7. Section 8 focuses on the Albertan approach the key regulatory elements of financial security, transfer or responsibility and post-closure stewardship. Section 9 concentrates on the structure of the project financing for CCS projects in Alberta, both in terms of level of public support, policy incentives and timing of payment disbursement. Section 10 reflects on the funding and regulatory approaches to CCS in Alberta identified in preceding sections, relates to the EU situation. Key findings are presented in Section 11.

4 Energy use and emissions in Alberta

The province of Alberta is located in Western Canada, and has a total area of 662,000 km^2, just slightly larger than the country of France. The province is rich in natural resources, including coal, minerals, natural gas, conventional oil and oil sands. Alberta is a global energy supplier, and has proven oil reserves of 170 billion barrels of oil, representing 98% of Canada's reserves, and 11% of total global oil reserves. Alberta has the third largest proven reserves globally, behind Venezuela (211 billion) and Saudi Arabia (265 billion). However unlike many other oil producing nations, 99% of Alberta's reserves are in the form of oils sands, also called bitumen. Bitumen requires further cleaning and treatment also known as 'upgrading', before it can be considered a crude oil. The primary consumer of crude oil from Albertan bitumen is the US, with 15% of US total oil imports being provided by Alberta (Alberta Energy, 2013a).

4.1 Emissions profile of Alberta

In 2010, 165 facilities from 15 industrial sectors reported a total of 122 $MtCO_2e$ greenhouse gas (GHG) emissions. CO_2 accounted for approximately 96% of total GHG emissions from Alberta. Oil sands operations account for the largest proportion of GHG emissions from the province, followed by electric power generation. Alberta has a total installed power generating capacity of approximately 14 GW, which generated 73 TWh in 2012. Coal accounted for 53% of electricity generated, with 37% from gas and just under 10% from renewables (Alberta Energy, 2013b). Due to methodological changes in emissions accounting, no representative long term trend can be provided for the province, however between 2009 and 2010, the most significant changes in emissions was a 3 $MtCO_2e$ increase from oil sands operations, and a 0.5 $MtCO_2e$ decrease from conventional oil and gas extraction (Province of Alberta, 2012).

Alberta's emissions distribution is characterised a relatively small number (29) of large emitters which account for 82% of total emissions. The top 8 emitting installations account for 45% of the total emissions, with 5 installations operating in the power sector and 3 in oil sands operations (Province of Alberta, 2012).

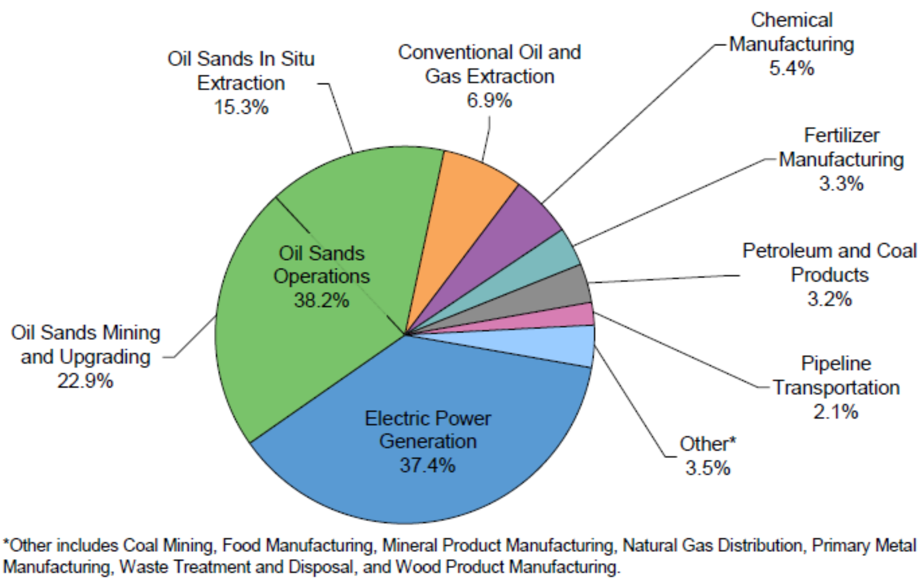


Figure 1: Contribution of 2010 Greenhouse gas emissions (Province of Alberta, 2012)

The province of Alberta is the largest emitter of CO_2 within Canada. In 2011, the province accounted for 35%, however the projections to 2020 made by the Canadian government expects Alberta's share to grow to approximately 40% by 2020. At 65 tons, the CO_2e per capita in 2011 was over 3 times the average of Canada. Whereas most provinces are expected to stabilise, or experience minor alterations in CO_2 emissions between 2011 and 2020, Alberta may increase its emissions by an additional 20% (Environment Canada, 2013). Therefore, commitments at a Federal level to curb greenhouse gas emissions could have extensive consequences for the province of Alberta. Likewise, Canada will face difficulties in adopting ambitious GHG reduction targets based on 1990 levels given the projected emissions increases expected in Alberta.

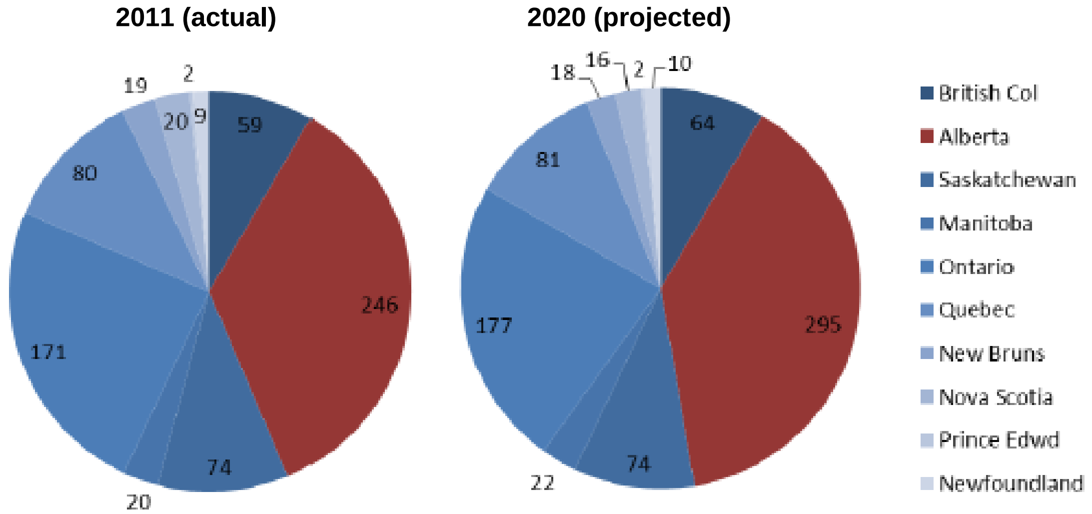


Figure 2: Breakdown of GHG emissions ($MtCO_2e/yr$), measured and projected across Canadian provinces (adapted, Environment Canada, 2013)

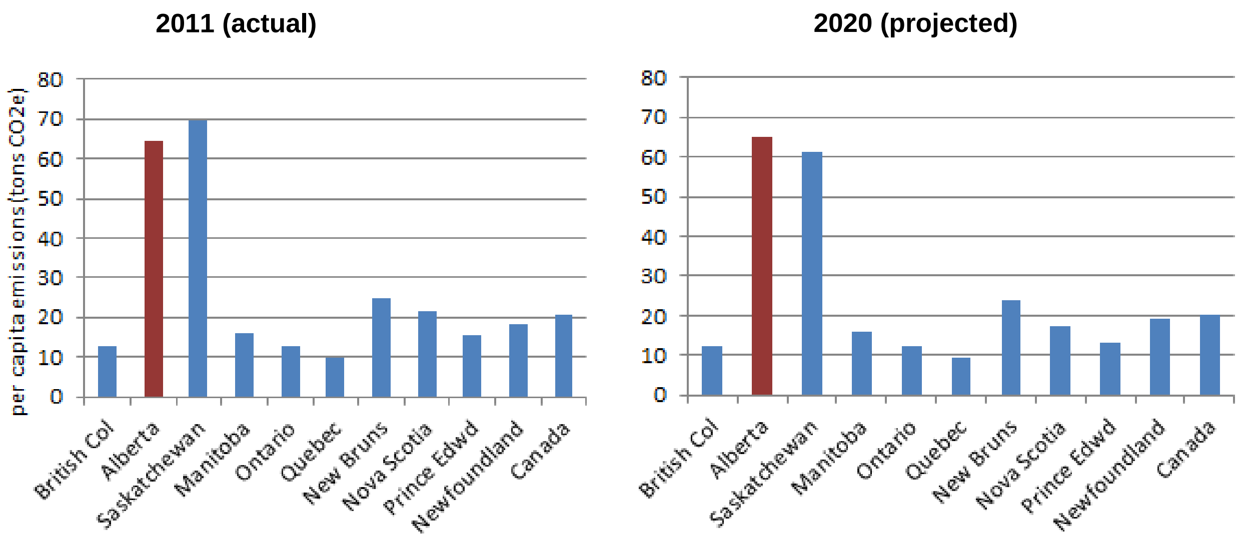


Figure 3: Breakdown of GHG emissions per capita (tons CO_2e), measured and projected across Canadian provinces (adapted, Environment Canada, 2013)

4.2 Alberta's climate goals

Alberta's 2008 Climate Change Strategy provided the high-level policy objectives for reducing greenhouse gas emissions across the province by 2050. From an initial GHG emission level of approximately 230 180 MtCO_2e in 2008, the strategy allows the total emissions to peak at around 250 MtCO_2e by 2020, after dropping to 180 MtCO_2e by 2050. Without action, business as usual emissions are predicted to rise to 300 and 350 MtCO_2e by 2020 and 2050 respectively. Three key routes for emission reductions are foreseen, conservation and energy efficiency, greening energy production, and the most significant reductions expected to be provided by CCS, as can be seen in Figure 4.

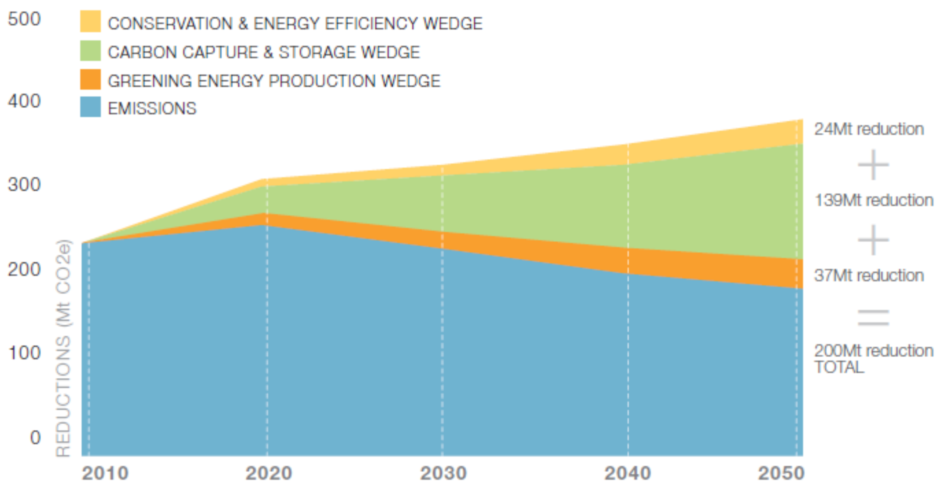


Figure 4: Alberta's greenhouse gas reduction targets (Government of Alberta, 2008a)

The province of Alberta has existing industrial activities involving the capture, transportation and injection of CO_2, for the primary purpose of CO_2 enhanced oil recovery. Furthermore, CCS is viewed as a highly compatible technology for Alberta, with the province having abundant storage potential, an existing wealth of knowledge and expertise from 60 years of oil and gas production, and a society that is familiar with large scale industrial infrastructure. Most importantly, CCS offers the opportunity for the province to curb the projected emissions growth from the rapidly expanding oil sands sector, positioning itself a responsible global energy supplier (Fernandez et al., 2013).

4.3 CO_2 emissions from oils sands production

As mentioned above, the primary cause of increasing CO_2 emissions in Alberta is related to the heat and energy requirements for the extraction and production of oil products from bitumen. There are two primary methods for extracting oil sands deposits. Approximately 20% of the recoverable reserves are close enough to the surface to be removed using conventional strip-mining methods to a depth of up to 75 meters. Around 50% of the bitumen extracted is currently surface mined. Deeper deposits of oil sands are produced using 'in-situ' recovery methods, whereby steam is injected into an oil sands reservoir to heat up and reduce the viscosity of the bitumen, making it possible to pump it to the surface. Because of the requirement for steam, in-situ methods are generally more GHG intensive than surface mining. Because of the larger total amounts of bitumen that are recoverable, and recent advances in extraction technology, in-situ recovery will become the primary route for bitumen production in the coming decades (Lattanzio, 2013).

The production of oil sands and derived products generally requires more energy because of two main reasons; 1) oil sands are heavier and more viscous than lighter crude oils; 2) oil sands are chemically deficient in hydrogen, have a higher carbon, sulphur and heavy metal content than light oils and therefore requires further processing before it can be used in a conventional refinery. This processing, termed 'upgrading', involves the removal of water, sand and wastes from the bitumen, catalytic purification (removal of excess sulphur, oxygen, nitrogen and metals), and thermal cracking, coking and hydrocracking to break-up longer chain hydrocarbons to more useful ones. The resulting product is referred to as synthetic crude oil (SCO) (Lattanzio, 2013).

The upgrading process as outlined above is in many cases additional to the extraction of conventional lighter oils, and therefore increases the energy intensity and resultant carbon intensity of the end-products. A review of available GHG life-cycle analyses of Canadian oil sands production, identified that on a Well-to-Wheel[1] (WtW) basis, emissions from transport fuel derived from oil sands were between 14-20% higher than the weighted average of transport fuels in the US (Lattanzio, 2013). In 2005, the US average WtW emissions for gasoline was 91g CO_2e/MJ, in comparison to transport fuels derived from oil sands at between 102-109g CO_2e/MJ[2] [3] for surface mining and SCO production, and between 108-120g CO_2e/MJ[4] [5] for in-situ and SCO production[6].

An important disclaimer, is that although literature indicates that the WtW wheel emissions of transport fuel derived from oils sands are generally higher than conventional crude, such calculations are greatly influenced by various assumptions and the completeness and quality of data used. Countries import a range of crude oils of which will have broad range of associated production emissions, with data often not available or reported. For example, oil produced in countries which flare considerable amounts of co-produced gas such as Nigeria and Iraq, could have WtW emissions that overlap with those of Canadian produced oil sands (Jacobs Consultancy, 2012).

4.4 CCS as a strategic technology for Alberta

The projected increase of oil sands operations and associated CO_2 emissions may have significant implications on provincial and federal climate strategies. Overseas however, certain jurisdictions which are taking a holistic approach towards de-carbonising their transportation sectors, are developing fuel standard policies that distinguish between upstream feedstocks for transport fuels based on the associated WtW CO_2e emissions. The European Union's (EUs) proposed Fuel Quality Directive[7] aims to reduce the greenhouse gas (GHG) intensity of fuel supplied in the EU for use in road vehicles and non-road mobile machinery. As part of this, fuel suppliers would have an obligation to reduce the emissions intensity (in gCO_2e/MJ) of their products by 6% by 2020, based on a 2010 baseline. The draft implementing measure (EC, 2009), if enacted, requires fuels suppliers to calculate the emissions intensity of their products using default lifecycle GHG intensity values. These default values reflect the higher emissions intensity of oil sands, as shown in Figure 5.

1 A well-to-wheel LCA includes all emissions from extraction, production, distribution and end-use.
2 Reference for lower figure AERI/TIAX, 2009.
3 Reference for higher figure NRCan, 2008.
4 Reference for lower figure GREET, 2010.
5 Reference for higher figure AERI/TIAX, 2009.
6 All data presented as lower heating values (LHV)
7 Directive 2009/30/EC

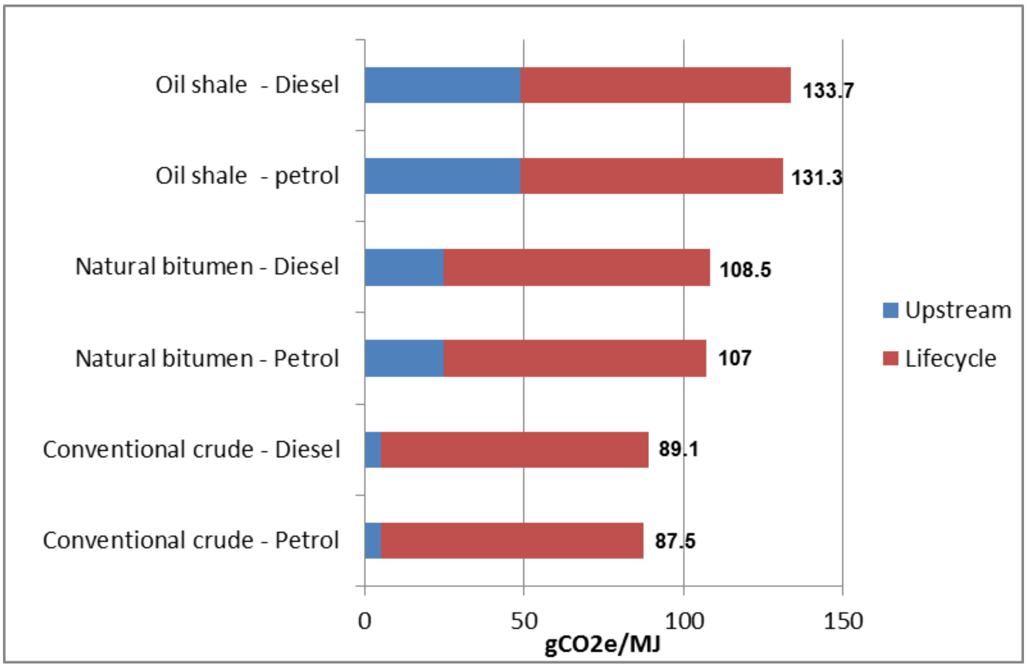


Figure 5: A range of default GHG intensity values for the proposed EU Fuel Quality Directive (adapted EC, 2009)

The passing of this Directive would mean that it would be harder for transport fuel suppliers to reduce the GHG intensity of their products by using feedstock derived from bitumen than from conventional crude oil. Although no oil from Alberta is currently sold to the EU, the Canadian government has openly challenged the EU on the Fuel Quality Directive, citing a number of methodological discrepancies in how the default LCA values have been derived. Specifically, the use of a single value for conventional crude is criticised as inaccurate and non-transparent. According to the Alberta Department of Energy (2013), the single values do not truly reflect the range of crude oils imported into the EU, and only 40% of crude production data is publically available for the current EU crude oil supply. A new decision on the Directive is expected in 2014, and although the outcome is unclear it is unlikely that the policy approach of distinguishing between the carbon intensity of transport fuels feedstocks will be reversed.

Furthermore, the EU is not the only jurisdiction that has developed policies that penalises transport fuel derived from bitumen. The California Low-Carbon Fuel Standard (LCFS) was the first piece of legislation that aims to reduce the carbon intensity of transport fuels. This legislation also associates upstream emissions intensity for SCO at over double the baseline average of 11.39g CO_2e/MJ, with values ranging between 18.74 and 24.49g CO_2e/MJ (ARB, 2009). Although such policies do not prohibit the use of SCO from Alberta, they could potentially reduce the margins for refiners in such jurisdictions, forcing oil sands producers to sell at a discount. The adoption of transport fuel policies by jurisdictions which penalize feedstocks with a higher carbon intensity would hypothetically restrict market access for Albertan oil sands producers.

Alberta is a landlocked province, and the expansion in oil sands production has caused capacity problems on existing transboundary pipeline infrastructure to the US. To maximize the revenue potential of the oil sands production, Alberta will need to increase its market access potential beyond Canada and the US, however this require the construction of new pipelines out of the province. The proposed Keystone XL Pipeline would have the capacity to transport 830,000 barrels per day of oil sands crude from Alberta to an oil hub in Nebraska (US), and then further to the Gulf Coast for refining and potential export. The cross-border project requires a Presidential Permit, but President Obama has so far blocked the project over fears that it would cause a net increase in US carbon emissions. Lattanzio (2013), has estimated the effect of the proposed Keystone XL pipeline on the U.S. GHG footprint to be an increase of 3.7 million to 20.7 million metric tons of GHG annually.

Both the environmental effects and the contribution of oil sands production to global greenhouse gas emissions have come under scrutiny by a number of jurisdictions, compounded by pressure from non-government organisations and the media. At the same time, the activity is becoming an increasingly important part of the Albertan economy, contributing a greater proportion to the province's GDP (see Figure 6). Therefore, CCS has a strategic importance for Alberta, as it could allow the province to develop oil sands resources while controlling the levels of associated CO_2 emissions.

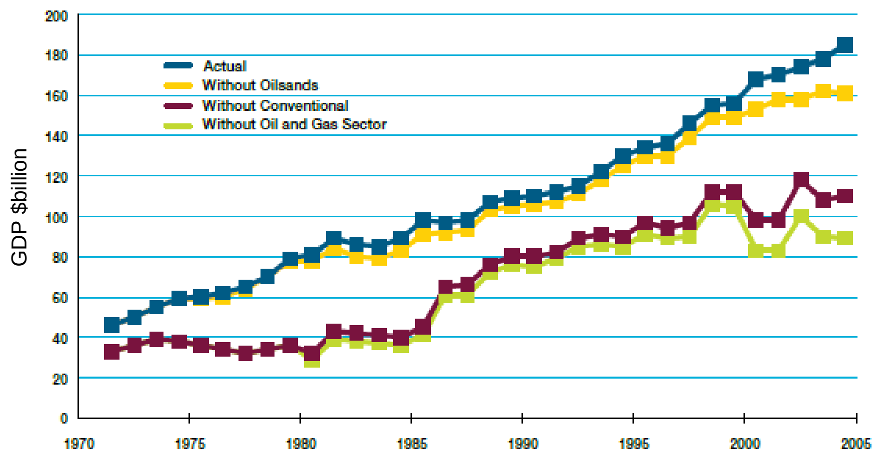


Figure 6: Impact of oil and gas on Alberta GDP (Government of Alberta, 2008b)

5 GHG abatement policy in Alberta

GHG abatement policy in Alberta initiated with the *Climate Change and Emissions Management Act*[8] which entered into force in 2003. The Act included a raft of regulation, including the *Specified Gas Reporting Regulation*[9], which has since 2004, obligated all facilities in the province which emit more than 100 ktCO_2e[10], to submit greenhouse gas emission reports. In 2005, Alberta's reporting program was harmonized with Canada's greenhouse gas emissions reporting program. On the 1st of July, 2007, Alberta became the first region in North America to introduce a GHG intensity target on all large emitting facilities. According to the *Specified Gas Emitter Regulation*[11] *(SGER)*, all facilities emitting over 100 ktCO_2e per year should reduce their emissions intensity per unit of production by 12 per cent below a historical baseline[12]. If the emissions intensity reduction target is not met through improvements in operations, the operator can achieve compliance through a number of penalties or offsets, as outlined below (Alberta Enviroment, 2007):

1. Contribute to the Climate Change and Emissions Management Fund: A payment of $15 per tonne of CO_2e to meet the reduction requirements

2. Alberta based offsets: Purchase Emission Offsets generated from projects by facilities not subject to the SGER that operated within the province after January 1st 2002.

3. Emission Performance Credits: Facilities applicable to the SGER who surpassed the emissions intensity target generate Emission Performance Credits. These credits can either be banked, or sold, and so provide an additional tool for compliance.

Since 2007, $312 million has been paid into the Climate Change and Emissions Management (CCEM) Fund, which in turn invests the funds into projects that support the development and application of clean energy technologies. $167 million has been invested into projects focusing on energy efficiency, renewable energy, cleaner conventional energy production and carbon capture and storage.

Alberta-based emissions offsets can be generated by facilities in accordance with technology specific quantification protocols which are approved by the government with help from experts and academia. As of 2013, there are currently just over 30 approved quantification protocols, and an additional number at a pre-approval review stage.[13] The basic quantification concept involves quantifying how many tonnes CO_2e have been achieved by an offset project compared to a baseline scenario. A protocol for emission offsets through CO_2 enhanced oil recovery (EOR) projects was available[14], however this is currently suspended due to methodological issues. A quantification protocol for CCS in deep saline aquifers[15] is currently in a pre-approval review stage, and is expected to be approved in the near future.

Successfully generated offsets are held on the Alberta Emissions Offset Registry. As of June 2013, registered projects had generated 28 MtCO_2e, of which 20 MtCO_2e have already be retired for compliance purposes. Both the amount and diversity of the offsets in the Registry has been increasing since 2007, as can be seen in Figure 7. Offset generators hold contracts with emitters, agreeing a price per offset, which can either take place prior or after issuance of a certified offset. The

[8] Statutes of Alberta, 2003. Chapter C-16.7
[9] Alberta Regulation 251/2004
[10] This threshold was reduced to 50,000 ktCO_2e effective as of 2010.
[11] Alberta Regulation 139/2007
[12] The average of the years 2003-2005.
[13] A full list of approved quantification protocols can be found here http://environment.alberta.ca/02275.html
[14] See http://environment.alberta.ca/02291.html
[15] The draft version of the CCS protocol is available here: http://carbonoffsetsolutions.climatechangecentral.com/offset-protocols/current-alberta-protocols-submitted-review

Albertan government does not have knowledge of the price agreed in contracts between offset generators and emitters, however the average price is thought to be between $8-10 (pers. comm, Fiorello).

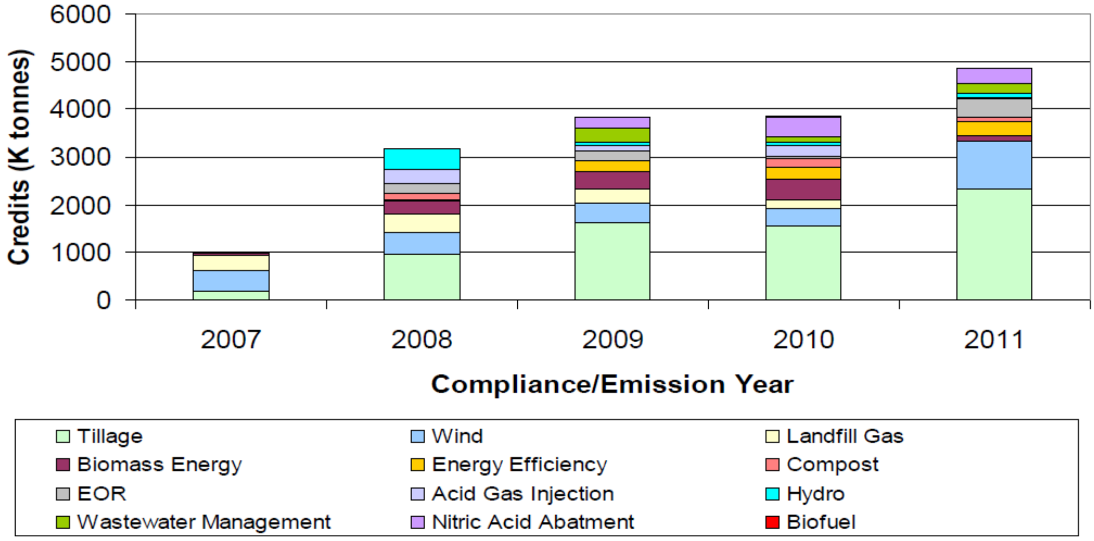


Figure 7: Offset credits submitted for compliance in Alberta[16]

Unlike other offset mechanisms, the government has taken a flexible approach to the issue of additionality, which has been applied so stringently under the Clean Development Mechanism of the Kyoto Protocol.[17] Projects operating prior to the implementation of the SGER in 2007, are also applicable to generate credits, as long as they were implemented prior to January 1st 2002, comply with an approved quantification protocol and are independently verified by a qualified third-party. Albertan policy-makers made this decision because they did not want to delay investment in clean energy projects, and penalize existing project investors. As of 2013, demand for offsets outstrip supply (pers. comm, Fiorello).

Emitters can achieve compliance without contributing to the CCEM, or purchasing offsets, by taking actions to reduce the emissions intensity of their operations, generating Emissions Performance Credits (EPCs). EPCs can be banked for future use, or can be sold to other installations for compliance purposes.

As of 2012, the SGER had achieved a reduction of 40 $MtCO_2e$, of which approximately 50 per cent has been achieved through the use of Alberta based offsets. Figure 8 displays the results of 2012, the 6th compliance year of the SGER, whereby emitters reduced emissions by 7.5 $MtCO_2e$ either through internal improvements or through other compliance pathways.

[16] Provided by the Government of Alberta
[17] Additionality is defined within the UNFCCC as a project activity is expected to result in a reduction in anthropogenic emissions by sources of greenhouse gases that are additional to any that would occur in the absence of the proposed project activity. Therefore any existing activities in operation are assumed to be profitable without the additional incentives of CDM offset credits.

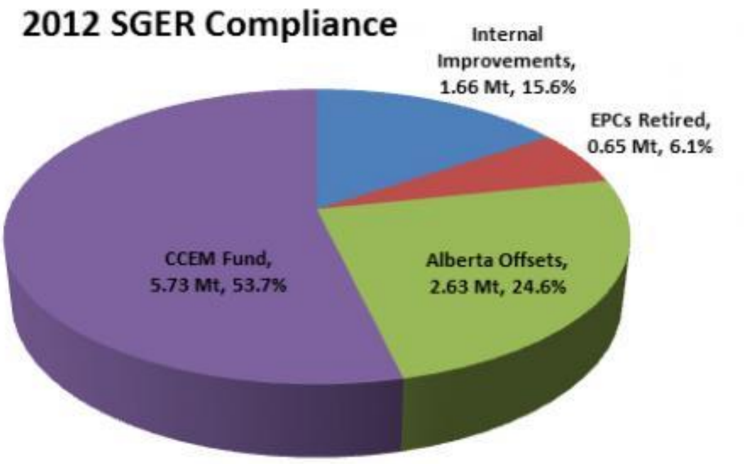


Figure 8: Results of the 2012 SGER compliance period (Carbon Offset Solutions, 2013)

6 Accelerating CCS in Alberta

In response to the Alberta's climate change strategy in 2008, whereby CCS was identified the most important GHG reduction technology for the province, the Government of Alberta formed the Alberta Carbon Capture and Storage Development Council. In 2009, the Development Council published the report, Accelerating Carbon Capture and Storage Implementation in Alberta (ACCSDC, 2009). This report assessed in more detail the strategic importance, the deployment potential, investment requirements, and the policy and regulatory obstacles that must be address to facilitate widespread deployment of CCS across the province. The key recommendations that have emerged from the report include (Province of Alberta, 2013):

- Financial investment from federal and provincial governments and the use of CO_2 for EOR are necessary to offset the financial disadvantages of CCS
- Funding and policy mechanisms should be put in place to promote large scale deployment of CCS
- The ownership of pore space and long term storage liability should be clarified by the government of Alberta.

In line with these recommendations, the Government of Alberta has made a number of regulatory changes to ensure the availability of provincial funding for CCS projects, and to enact legislation to provide a regulatory framework for CCS. Further detail on these actions is provided in the sections below.

6.1 The Carbon Capture and Storage Funding Act

The Carbon Capture and Storage Funding Act[18] was passed in 2009, to encourage and expedite the design and construction of CCS in Alberta. The act states that the aggregate of all payments from the Alberta governments general revenue fund for CCS projects, will not exceed $2 billion. The call for proposals to apply for government funding for CCS projects, was actually released in 2008. The call resulted in a total of 54 expressions of interest being submitted. The selection process was based on transparent criteria, and only projects that integrated capture, transport and storage components were applicable. After the initial selection process, 10 projects were invited to submit full project proposals. In 2009, 4 CCS projects were selected to receive funding.

6.2 The 2010 Carbon Capture and Storage Statues Amendment Act

Prior to 2010, Alberta had no specific legislation concerning the long-term storage of CO_2. The injection of CO_2 for the purpose of enhanced oil recovery was permitted however, through provisions in Alberta's Oil and Gas Conservation Act[19], utilizing the same regulatory regime as acid gas disposal. The Carbon Capture and Storage Statutes Amendment Act passed in 2010, altered a number of the province's energy statutes to provide regulatory clarity on a number of issues, particularly the ownership of pore space and the long-term liability of CO_2 storage sites. The new legislation is retroactive, regardless of pre-existing mineral or storage rights.

Key legislative adjustments enacted by the CCS Statutes Amendment Act, are to be found in the provincial Mines and Minerals Act[20] (MMA), the Energy Resources Conservation Act, the Oil and Gas Conservation Act (OGCA), and the Surface Rights Act[21]. The majority of the additional regulatory

[18] Statutes of Alberta 2009, Chapter C-2.5
[19] Revised Statutes of Alberta 2000, Chapter O-6
[20] Revised Statutes of Alberta 2000, Chapter M-17
[21] Revised Statues of Alberta 2000, Chapter S-24

provisions for CCS have been made to the MMA, which governs the management and disposition[22] of rights in Crown owned mines and minerals. The most salient additions to the MMA are:

- A new provision which declares all pore space under the surface of all land[23] in Alberta is vested in and property of the Crown in right of Alberta, independent of whether rights are held for mineral extraction, or mineral or water extraction is taking place (s15.1).

- Defines legally the interpretation of 'captured carbon dioxide', 'storage rights' and 'sequestration[24]'.

- Via a new section of the MMA, 'Part 9 – Sequestration of Captured Carbon Dioxide, a disposition regime for Crown owned pore space has been established, including:
    - Rights to drill evaluation wells (s.115)
    - Rights to inject carbon dioxide for sequestration (s.116), encompassing;
        - The requirement to submit a monitoring, measurement and verification (MMV) plan for approval, and subsequent compliance thereof.
        - The requirement to submit a closure plan for approval, and subsequent compliance thereof.
    - The issuance of a Closure Certificate (s.120), so long as *inter alia:*
        - the closure period specified in the regulations has passed
        - the captured carbon dioxide is behaving in a stable and predictable manner, with no significant risk of future leakage

- The creation of a mechanism for transferring long term liability, monitoring and post-closure responsibilities from the operator to the crown (s.121), assuming that a closure certificate has been issued in accordance with s.120 of the MMA. The regulation indemnifies the operator with respect to any liability related to the injected carbon dioxide, including damages in tort.

- The establishment of a Post-closure Stewardship Fund (PCSF) (s.122), which must be contributed to by the operator in the form of a fee, and which may be used for the purposes of:

    - Monitoring the behaviour of captured carbon dioxide that has been injected
    - Fulfilling any obligations that are assumed by the Crown pursuant to s.121
    - Paying for suspension costs, abandonment costs and related reclamation or remediation costs in respect of orphan facilities

Amendments to the OGCA, include a definition of 'captured carbon dioxide' identical to the MMA, but also provisions which allows the regulator[25], once a Closure Certificate is issued in accordance with Part 9 of the MMA is issued, to amend a well licence or facility approval to reflect that the Crown becomes the holder of the license or approval [s23.1(a)], and that the former holder is relieved from all obligations related to that well or facility. The existing regime for oil and gas wells, have no provisions for a transfer of responsibility from licence holder to the Crown, with the holder liable for well or facility in perpetuity, unless utilized or disturbed by a third-party.

Another addition to the OGCA, excludes any facility[26] or well[27] used in connection or associated with the disposal of captured carbon dioxide from being applicable to the 'Orphan Fund'[28]. Holders of licences for wells or facilities under the OGCA, must pay into an orphan fund via a levy set by the

[22] A legal term to communicate management or control
[23] With the exception of Federal Crown land
[24] Sequestration is defined as 'permanent disposal'
[25] The Alberta Energy Regulator – see sub-section 5.4
[26] s.68(i)(vii.3)
[27] s.68(g.1)
[28] Defined in Part 11 of the OGCA

regulator, of which it may be used for instances of abandonment whereby there is no legally responsible or financially able party to deal with reclamation. The potential costs of reclamation of abandoned wells or facilities associated with CCS projects, will be included in the rate set by the regulator through the PCSF instated within the MMA.

6.3 Carbon Sequestration Tenure Regulation 2011

The Carbon Sequestration Tenure Regulation[29], also known as the CS Tenure Regulation, was issued by the Government of Alberta in April 2011, as an appendix to the MMA. The CS Tenure Regulations provides an additional set of definitions, notably defining a "deep subsurface reservoir" as "in respect of a permit or lease, means the pore space within an underground formation that is deeper than 1000 metres below the surface of the land within the location of that permit or lease"[30] . "Pore space" under the MMA, is also defined as "the pores contained in, occupied by or formerly occupied by minerals or water below the surface of land".

Importantly, the CS Tenure Regulation expands on Part 9 of the MMA described above, by outlining the process of gaining and restrictions of the right to drill evaluation wells (s.115 of the MMA), via the acquisition of an "evaluation permit"[31], the process of gaining and restrictions of the right to inject carbon dioxide via the acquisition of a "carbon sequestration lease"[32]. The key features of an evaluation permit and a carbon sequestration lease are outlined below:

- Evaluation permits – Allows the drilling of wells to assess the suitability for the sequestration of CO_2, and provides no right to any minerals within the location of the permit. The term of an evaluation permit is 5 years, and the location of an evaluation permit must not exceed 73, 728 hectares (~734 km2). An evaluation permit will not be granted without an approved monitoring, verification and verification plan. A rental for a year of the term is payable at the rate of $1.00 per year for each hectare in the area of the location of the permit or lease, subject to a minimum of $50 per year.

- Carbon sequestration lease – Allows the drilling of wells for evaluation and injection of CO_2 in deep subsurface reservoirs. The term of a lease is 15 years, and the location of the lease must not exceed 73, 728 hectares. The rental terms are identical to the evaluation permit.

The CS Tenure Regulation also outlines the requirements of the MMV plans specified in the MMA, and obligations for the attainment of a Closure Certificate, as per s.120 of the MMA. Notably, the regulation informs that contributions to the PCSF are to be made based on a fee per tonne of captured carbon dioxide injected into the location of a carbon sequestration lease at the rate established by the Minister.[33]

6.4 Institutional roles and responsibilities

At present, CCS projects in Alberta are regulated via two primary entities;

- **Alberta Energy** - a ministry of the Government of Alberta, is responsible for ensuring the development of Alberta's resources. Alberta Energy develops policies and strategies to manage the extraction of fossil fuel resources, developing alternative energy sources, maintaining competitive system of royalties and controlling emission reduction efforts.

[29] Alta. Reg.68/2011
[30] S1.(c)
[31] See section 3 of the CS Tenure Regulation
[32] See section 9 of the CS Tenure Regulation
[33] Please see section 7.3 for further information on the development of the PCSF rate calculation methodology

- **Alberta Energy Regulator (AER) -** the AER is an industry funded corporation that regulates oil, gas and coal development in Alberta. The AER succeeded the Energy Resources Conservation Board in 2013, in an effort by the Government to consolidate regulatory oversight of energy resource development in the province.

The regulatory approval process that the two existing CCS projects, Quest and the ACTL, have undergone, precedes the establishment of the Alberta Energy Regulator. Because of this, the interaction between Alberta Energy and the AER has yet to be tested to the entirety of the available legislation. Based on an assessment of the 2010 Carbon Capture and Storage Statues Amendment Act and the Carbon Sequestration Tenure Regulation 2011, a basic interpretation of the division of tasks between the two institutions is outlined in Table 1.

Table 1: Basic division of responsibilities between Alberta Energy and the Alberta Energy Regulator in regulating provincial CCS projects

Alberta Energy	Alberta Energy Regulator
Grant rights for evaluation of subsurface	Well license applications
Grant tenure agreement for the injection of CO_2 into Crown owned pore space	Injection scheme approvals
Evaluation of MMV plans	Storage site closure certificate approval
Storage site closure certificate issuance	Undertaking or appointing third-party to undertake reclamation work if necessary
Administration of PCSF	Designate orphan CCS wells, facilities

The interaction between Alberta Energy and the AER in authorizing and controlling CO_2 storage activities has been highlighted is requiring clarification in a recent regulatory assessment conducted by the Government of Alberta. Particularly better distinction of the roles and responsibilities of the two entities during the process of issuing storage site closure certificates has been recommended. A key recommendation of the steering committee that presided the Albertan CCS regulatory framework assessment, was that the Government of Alberta and the AER should coordinate the development of a CCS Regulatory Guidance Document, which provides detailed information on the approval process and on the roles of governmental departments and the AER (Alberta Energy, 2013).

7 CCS projects in development

The Carbon Capture Funding Act 2009, outlined in section 6.1, succeeded in selecting four potential CCS demonstration projects in the province. Since then however, two of four projects, the Swan Hills Synfuels project and TransAlta's Pioneer project, have been cancelled due to poor economics despite the availability of public funds. The two projects that are progressing are the Quest CCS Project and the Alberta Carbon Trunk Line projects.

7.1 Quest CCS Project

Quest is part of the Athabasca Oil Sands Project (AOSP), a joint venture between Shell (60%), Chevron (20%) and Marathon (20%) oil companies. The goal of the AOSP is to increase production of synthetic crude from 255,000 b/d, to potentially over 700,000 b/d. In order to be able to process the increased amount of bitumen into syncrude, an existing bitumen upgrader, called the Shell Scotford upgrader, in Fort Saskatchewan near the city of Edmonton will be expanded to increase its original process capacity of 255,000 b/d with an additional 100,00 b/d. As part of the expansion project, additional steam methane reformer units will need to be added on site to produce hydrogen needed for upgrading the bitumen. The process of steam methane reforming requires the removal of CO_2 from the process gas that results in a stream of pure hydrogen. The removal of CO_2 using amine solvents also results in a stream of CO_2 with a concentration of 95%, which is regularly vented into the atmosphere, but highly suitable for dehydration, compression, transport and storage.

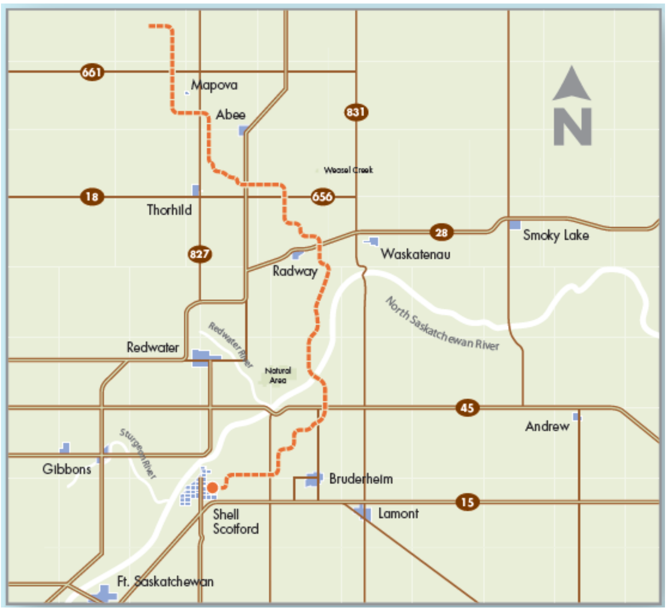


Figure 9: The planned route of the Quest CCS Project CO_2 pipeline (Shell, 2010)

The Quest CCS Project will divert 35% of the total CO_2 generated by the Scotford upgrader to geological CO_2 storage. Approximately 1.1 $MtCO_2$ per year will be dehydrated, compressed and transported in a 12-inch diameter pipeline for 80 kilometres, then injected to a depth of 2 km into a deep saline formation called the Basel Cambrian Sands. The project received approval by the Government of Alberta in 2012, and construction on the capture unit and transportation pipeline commenced in early 2013. Injection is expected to take place in 2015, and continue for a period of 25 years. Information on the cost and financing of the Quest CCS project is documented in Section 9.1.

7.2 Alberta Carbon Trunk Line

The Alberta Carbon Trunk Line (ACTL) is a proposed 240 km pipeline that would transport CO_2 from emission sources in Alberta's industrial heartland North of Edmonton, for injection and storage in oil fields for the purposes of enhanced oil recovery (EOR). The project has been initiated by Enhance Energy Inc, a company specializing in (EOR), who's founders have had previous success with CO_2 flooding and storage in the Weyburn oil fields in the Canadian province of Saskatchewan. Enhance Energy Inc have agreements in place for CO_2 off-take with an existing fertilizer plant operated by Agrium Inc (~0.6 $MtCO_2$/year), and a bitumen upgrader and refinery which is currently being constructed by the North West Redwater Partnership (~1.2 $MtCO_2$/year). The planned 12-inch pipeline is licensed for an initial 5.5 $MtCO_2$/year, however it has a design capacity of 14.6 $MtCO_2$ (Enhance Energy Inc, 2013). Therefore significant scope exists for connection to additional CO_2 emitters operating in the Edmonton region.

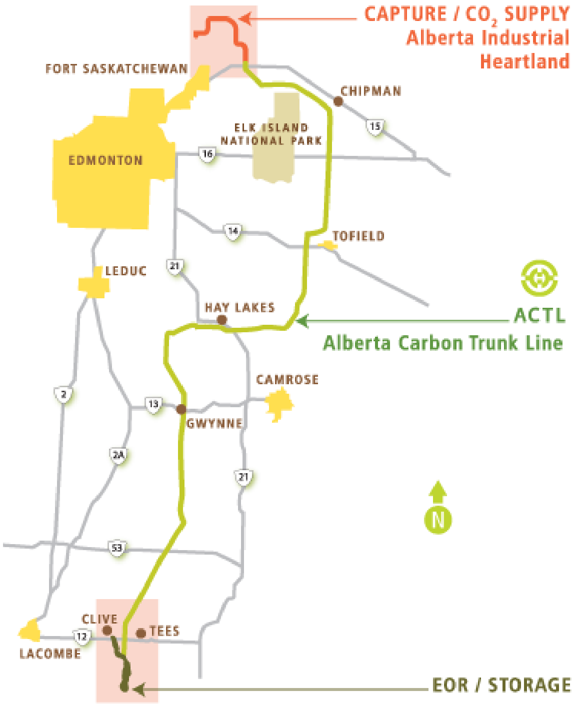


Figure 10: The planned route of the Alberta Carbon Trunk Line (Enhance Energy Inc, 2013a)

The project has secured initial commitments for provincial and government funding. Clearing the right of way (ROW) for the pipeline commenced in 2013, and procurement of pipeline infrastructure has taken place. The CO_2 will be delivered to the oil fields near the small town of Clive in central Alberta, which require the CO_2 to maximise the amount of light oil that can be recovered from existing fields. The initial flooding of the Clive reservoir has the potential to recover an additional 220 million barrels of oil, however the expanding the EOR operation to other fields in the close vicinity could increase this figure to 1 billion barrels of oil. An EOR operation at this scale could expect to store a total of 2 $GtCO_2$ (Enhance Energy Inc, 2013b).

The ACTL project includes drying and compression facilities on the Agrium and North West Upgrader sites, the Elk Island Pump Station to the east of Fort Saskatchewan and facilities at the south end of the system, near Clive, to allow distribution of CO_2 to oil and gas fields in the area. The pipeline construction is expected to be completed in mid-2015, coinciding with the completion phase of the Agrium fertilizer plant's capture and compression unit. Injection into the Clive reservoir is expected in 2016, with the construction of the North West Upgrader finished in the same year.

8 Regulatory approaches to financial security, long-term liability and post closure stewardship of CO_2 storage sites

The CCS Statutes Amendment Act 2010 introduced a mechanism within the province's Mines and Minerals Act which allows the conditional transfer of long-term liability from the operator to The Crown. The same regulation also introduced the concept of the Post-Closure Stewardship Fund (PCSF), of which the following Carbon Sequestration Tenure Regulation stated that operators must contribute to the fund on a fee per tonne of CO_2 stored, at a rate set by the regulator. While the above regulation provides an important legal framework to facilitate CCS, many underlying details and guidelines have not been established. In particular, the regulations provide no indication on the length of the closure period prior to transfer of responsibility, and how the payments into the PCSF will be calculated and managed.

8.1 The Regulatory Framework Assessment

In order to assess the suitability of the existing regulatory framework for CCS in Alberta, in 2011 Alberta Energy launched the CCS Regulatory Framework Assessment (RFA) (Alberta Energy, 2013c). The RFA was a multi-stakeholder process guided by a steering committee which included a panel of international experts, from government, industry, academia and non-governmental organisations. Feeding into the expert panel where four working groups each with a specific focus: monitoring, measurement and verification, regulatory issues, geology/technical and environmental. Concluding in late 2012, the RFA resulted in a detailed set of recommendations for regulatory adjustments and additions to enable CCS to be deployed in a safe, responsible and efficient manner. Recommendations were developed for the following areas:

- Applications, approvals and regulatory framework
- Risk assessment, monitoring, and technical requirements
- Public consultation and notification, surface access, and public safety
- Site closure and long term liability

In additional to regulatory changes, a number of other recommendations were made which included the improving the role clarity of government entities in regulating CCS projects, and the development of guidance documents to support potential CCS project applicants through the permitting process.

The following sections focus on two key elements of CO_2 storage regulation that have received attention in the European Union as possible obstacles to the broader deployment of CCS.

8.2 Transfer of liability

The provincial Mines and Minerals Act (MMA) allows the transfer of liability from the storage site lessee to the Government of Alberta once a closure certificate has been awarded by the regulator. The Government of Alberta then assumes all obligations of the lessee under the Oil and Gas Conservation Act (OGCA), the Environmental Protection and Enhancement Act[34] (EPEA), and the Surface Rights Act (SRA). The issuance of the closure certificate also indemnifies the lessee against liability for tort damages. The MMA states that a closure certificate can be issued after a closure period set by the regulator has elapsed, and that the CO_2 is behaving in a stable and predictable way with no significant risk of future leakage.

[34] Revised Statutes of Alberta 2000 - Chapter E-12

The closure period, although not defined in the regulations, is assumed to begin when no more CO_2 injection will occur. In the RFA, a minimum closure period of “no shorter than 10 years” has been recommended, before the Government of Alberta can grant a closure certificate to assume long-term liability. The RFA recognises that most jurisdictions that explicitly allow the transfer of responsibly of CO_2 storage sites require a minimum time period to pass. The RFA steering committee states that the minimum closure period of 10 years is required for two key reasons:

- To allow time for the Government to be confident about the sustained nature of compliance with the performance criteria prior to issuing a closure certificate
- To enhance public confidence in the closure and transfer process

The RFA stresses that the innovativeness of the CO_2 storage concept, a lack of relevant standards, and that no projects have yet gone through the closure process, validates the decision for a minimum closure period. However, it also recommends that as experience in the field of CCS increases, the Government of Alberta should re-evaluate the appropriateness of the minimum closure period.

Another important recommendation from the RFA, relates to the liability related to the loss of CO_2 credits in the case of leakage after the issuance of the closure certificate. In the near future, CO_2 storage projects will be able to generate offset credits with a value of up to $15 for each tonne of CO_2 stored under the Specified Gas Emitters Regulation (SGER). In the case that an amount of CO_2 leaks from the storage site, an equivalent amount of offset credits would be void and therefore cancelled. This would have financial consequences for whichever emitter had utilised the offset credits to comply with the SGER.

In the MMA as of 2013, the issuance of the closure certificate does not trigger the transfer of liability of CO_2 offset credits from the lessee to the Government of Alberta, as these are regulated under the Climate Change and Emissions Management Act which is not stated in the relevant section (s.121) of the MMA. The RFA states that to ensure consistency with other forms of liability, liability related to CO_2 offset credits should also be transferred to the government, and recommends that the MMA is amended to facilitate this. The lessee however remains fully liable for any leakage prior to the issuance of the closure certificate after the stated 10 year period.

8.3 The Post-closure Stewardship Fund

The Post-closure Stewardship Fund (PCSF) for CO_2 storage is established under the MMA. The purpose of the PCSF is to cover the costs associated with some of the assumed liabilities and obligations in the post-closure period of a CCS project, in order to protect the Alberta public from potential excessive costs. The PCSF is only applicable for CO_2 storage projects, and not EOR projects as the government assumes no post-closure liability with relation for EOR projects. The lessee must pay a fee into the PCSF per net tonne of captured CO_2 injected into the storage location. The fee has yet to be established, but it is expected to be set by Ministerial Order on a project by project basis using a standard methodology.

As of October 2013, a PCSF Working Group composed of 30 experts from government, industry, NGO’s and academia has been created to develop the methodology to set the PCSF rate. The group is working with external consultants to reach an agreement on the rate by mid-2014, as it must be in place prior to commencement of the Quest CCS Project in 2015. Although the rate will be calculated on a project-by-project basis, contributions from individual projects will be pooled into a consolidated fund. The RFA has provided a number of recommendations on how the methodology for the PCSF rate should be developed:

- It should be set on a risk-based and probability-weighted basis;
- Be based on only the specifics of the lessee’s project;
- Should not increase due to withdrawals from the PCSF, or risks with other projects;

- The rate should be reviewed every 3 years, with adjustments (positive or negative) be made on a go-forward basis and not be retroactive.

The purpose of the PCSF has also been defined to include five cost categories or 'rate components' (Alberta Energy, 2013a):

1. Monitoring costs in the post-closure period:
   - As required in the MMA
2. Liability obligations assumed by the Government of Alberta:
   - Under the OGCA, EPEA, SRA
3. CCS orphan facility levy
   - For the purposes of paying for suspension costs, abandonment costs and related reclamation or remediation costs in respect of orphan facilities
4. Climate emission costs *(as recommended in the RFA)*:
   - Responsibilities under the Climate Change and Emissions Management Act, i.e. liability relating to the loss of CO_2 offset credits.
5. Administrative costs
   - PCSF management and data management

Using the Quest CCS project as the case study, the PCSF Working Group is therefore engaged in developing monetary estimates of the assumed liabilities (1-5 above) at the point of issuance of the closure certificate. It is assumed that the total estimate costs will then be spread across the expected total amount of CO_2 to be injected to arrive at a fee per tonne injected. The PCSF does not include compensation to affected third parties (tort liability), which are fully borne by the government after closure.

8.4 Financial security

At present, contributions to the PCSF would be the only form of financial security that must be legally provided for CCS projects. However, the RFA recommends that a lessee should also post a financial security sufficient to cover the full expected costs of suspension, abandonment, remediation and reclamation, including surface and sub-surface costs, in the case that the CO_2 storage project (*excluding* capture and transport) is orphaned prior to the issuance of the closure certificate. The reason for the required upfront security rather than relying on the PCSF, is that the expected costs as outlined above are dependent on the amount of infrastructure in place rather than the amount of CO_2 injected (Alberta Energy, 2013c). The financial security would be returned to the lessees once the closure certificate is issued. If this recommendation would be adopted in law, the Alberta Energy Regulator would be tasked with the calculation and providing guidance on acceptable forms of the required financial security. The financial security amount is independent from contributions to the PCSF.

For the Quest project, in order to receive the provincial funding after completion of the project milestones (see Section 9), the Government of Alberta does require that the partnership provides a "letter of credit" to the Government. These letters of credit can become effective if the project does not reach successful commercial operation. Once the project successfully reaches commercial operations, the Government returns the letters of credit to the partnership. It is expected that the ACTL must also provide this assurance.

Figure 11 provides an overview of the proposed liability regime for the different phases of a CO_2 storage project in Alberta.

<table>
<tr><th></th><th colspan="3">PROJECT PHASE</th><th></th></tr>
<tr><th></th><th>Operational</th><th>Closure</th><th>Post-closure</th><th>Orphaned Project</th></tr>
<tr><td>Suspension, Abandonment, Remediation and Reclamation of facilities</td><td>Operator</td><td>Operator</td><td>PCSF</td><td rowspan="2">1. Financial Security (as per Recommendation 1)
2. Working Interest Participants
3. PCSF</td></tr>
<tr><td>MMV</td><td>Operator</td><td>Operator</td><td>PCSF</td></tr>
<tr><td>Compensation to affected third parties (if necessary)</td><td>Operator</td><td>Operator</td><td>Government of Alberta (not PCSF)</td><td>Working Interest Participants</td></tr>
</table>

Figure 11: the proposed liability regime for CO_2 storage projects in Alberta[35]

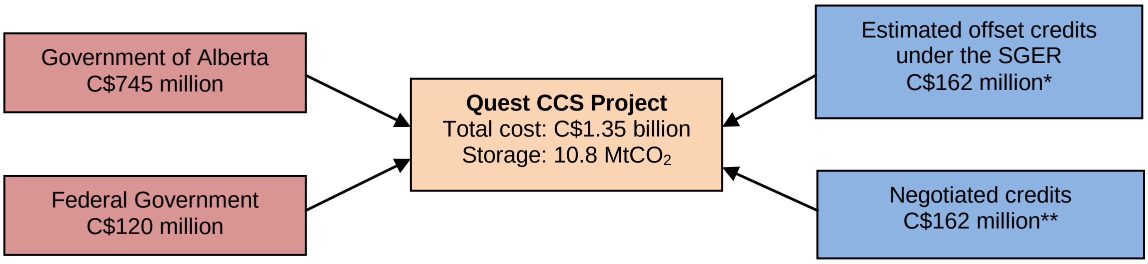
[35] A “working interest participant” means a person who owns a beneficial or legal undivided interest in a well or facility under agreements that pertain to the ownership of that well or facility. A specific oil and gas term, with a CCS project this can be interpreted as any party that has directly invested in the CO_2 storage project.

9 Project financing and long-term incentives

CCS projects in Alberta are financing by direct provincial and federal grants and private capital, with revenues associated with carbon offsets and through enhanced oil recovery. The government funded grants are awarded in payment installments according to each projects stage of completion. The installments are based on a 40-20-40 split. The first 40% is provided during the construction of the projects, with payments contingent on separate engineering milestones agreed between the operator and Alberta Energy. The second 20% is a lump sum payment on achievement of commercial operation for a period of 30 days. The remaining 40% is paid out in the operation phase, in 10 annual installments after the date of commercial operation. The installments are based on actual tonnes stored, with the rate based on a pre-determined dollar per tonne payment. Beyond 31st December 2025, no further installments will be provided. The funding contracts do not allow the total funding provided to the project by the province of Alberta to exceed 75% of the incremental project costs, less any other public funding received.

9.1 Project financing: Quest CCS Project

The total capital and operating cost of the Quest CCS Project over a 10 year period is stated as $1.35 billion. The total financing contributed to the project by the Government of Alberta was $745 million, with an additional $120 million from the federal Clean Energy Fund. The project will also be applicable to generate Alberta based offset credits which have a value of up to $15 dollars at the time of writing. Furthermore, Shell has also negotiated a two-for-one deal with the province on the amount of offset credits generated. The additional negotiated credits cannot be sold to other emitters so can only be used to offset other emissions generated by Shell. These negotiated credits have received criticism, as although they are linked the performance of the project, do not actually represent emissions reductions under the SGER. As the project is already generating offsets, which can be sold to allow others to emit, the issuance of the negotiated emissions means that the Quest CCS Project is actually a carbon positive initiative (Pembina, 2011).



*Total planned storage (tCO_2) x maximum offset value (C$15)
** Expected worth of credits

The Quest CCS project receives during the construction and 10 year operating phase, $865 million. Assuming that the project achieves its planned storage target, the project would generate $162 million worth of offset credits, plus $162 million in negotiated credits. Therefore the total government support plus the maximum value of offsets generated is understood to be $1.19 billion, an investment deficit of $160 million. However, if the value of offset credits increase under the SGER increases, and the emissions intensity target is raised above the current 12%, the Quest CCS Project could break-even or possibly reach a positive net present value within the 10 year period.

9.2 Project financing: Alberta Carbon Trunk Line

The total capital and operating costs of the ACTL project over a 10 year period are estimated to be $1.2 billion. The project will receive a total of $495 million in provincial funding, and $63 million in federal funding (Enhance Energy Inc, 2013b). The project will also able to generate offset credits under the SGER, however whether the project will receive negotiated offset credits in alignment with the Quest CCS Project has not yet been openly discussed by the provincial government and project developer. The most important revenue stream for the projects is associated with the additional revenue from the enhanced oil recovery operations facilitated by the delivery of the CO_2 to the oil fields in Clive.

10 Reflection on EU approach to CCS demonstration

Since 2008, the European Union has developed and launched two financial support programmes to accelerate the deployment of CCS. The European Energy Programme for Recovery[36] (EEPR) and the New Entrants Reserve 300[37] (NER300) launched in 2008 and 2010 respectively, have yet to successfully support the implementation of a single CCS project to date. Generally speaking, the failure of the financial support programmes can be attributed to the underlying policy mechanism, the EU Emissions Trading Scheme, which has not provided a stable price on carbon high enough to stimulate long-term investments in CCS. It is not the objective of this paper to directly compare the progress of CCS demonstration between the EU and the province of Alberta, differing economic, political and geographical factors render such an exercise futile. However, a concise analysis of the approaches adopted by the two jurisdictions on key issues, such as project financing and long-term liability of CO_2 storage sites provide useful insights for both EU and Albertan policy makers.

10.1 Project financing

The project financing in Alberta is provided by the Carbon Capture and Storage Funding Act of 2009. The fund is comprised of a total of $2 billion (€1.38 billion) to fund up to 4 CCS projects. The funding support can reach of maximum of 75% of the incremental capital and operation costs over a 10 year period. The funding schedule allows the operator to recoup costs during the engineering (40%), commissioning (20%) and operational phase (40%) of the project. Further policy incentives are provided by the Albertan Specified Gas Emitters Regulation offset protocol for CO_2 storage in saline aquifers, which allows the storage operator to generate emission offsets with a value of up to $15 per tonne of CO_2 successfully injected and stored. Rather controversially (See Pembina Institute, 2011), the 2 CCS projects within the CCS Storage Funding Act may also receive so called ‘negotiated-credits’, equal to the actual amount of offset credits generated which can be used to offset emissions within the project proponents own company.

The Quest CCS project, has a total of $865 million (€600 million) in project financing from public sources, approximately 65% of the total of project costs. The underlying policy mechanisms and negotiated credits may reach an estimated $324 million (€223 million) assuming the planned injection campaign is successful. Based on these figures, the Quest CCS project does not quite reach an economic business case, but would only require a relatively small amount of private investment funding, approximately 8%[38]. The SGER is due for revision in 2014, and it has been reported that the government could be considering an emissions intensity higher than the current 12% target, and a higher price for the contribution of the Climate Change and Emissions Management Fund, potentially reaching $40/t$CO_2$ (€27) from the current $15/t$CO_2$ (€10) (Pembina Institute, 2013). In such a situation, the Quest CCS project, including the public project financing, would become an economically viable project for the operator.

Through the EEPR, the European Commission had set aside €1 billion ($1.45 billion) to fund six CCS projects. The maximum amount of community funding provided to each CCS project was €180 million ($260 million). Individual Member States could also provide public funding in addition to EU funding. Five of the six projects appeared to have stalled and will not reach planned completion. The ROAD CCS project in Rotterdam, which would also receive €150 ($220) million in state support from the government of the Netherlands, is expected to make a final investment decision in early 2014. The project is understood to have a significant funding gap. All of the CCS projects included in this EEPR funding programme were power generation projects, with CO_2 being captured from flue gases of post-combustion of oxyfuel CCS projects.

[36] http://ec.europa.eu/energy/eepr/
[37] http://ec.europa.eu/clima/policies/lowcarbon/ner300/
[38] This is a crude assumption based on publicly available data.

The NER300 involved auctioning 300 million EU ETS allowances and use the proceeds to financially support CCS and innovative renewable projects. At the inception in 2010, the programme was expected to generate €4.5 billion through the auction, but the low EU ETS price during auctioning in 2011 and 2012 the first 200 million credits were expected to generate just €1.5 billion. The NER300 is a bidding process, whereby the projects to receive funding are ranked by a 'cost per unit performance', i.e. for CCS the most CO_2 stored per euro of funding requested. The funding instrument allows project operator to claim up to 50% of relevant costs[39] associated with a CCS project. The financial support was based on annual performance payments over a 10 year period. Upfront funding could be applied for, however this must be guaranteed by the Member State where the project would take place, however it is understood that some Member States were reluctant to do this (DECC, 2013). Due to the reduced capital generated through the auctioning process, and a rule that restricts any project to receive more that 15% of the total available allowances, funding for CCS projects is limited to approximately €300 million.

10.2 Long-term liability of CO_2 storage sites

The Albertan Mines and Minerals Act (MMA) allows the transfer of liability from the storage site lessee to the Government of Alberta once a closure certificate has been awarded by the regulator. At the time of writing, the length of the closure period between the cessation of CO_2 injection and the transfer of responsibility to the Albertan government is not provided in the regulation. However, the steering committee of the CCS Regulatory Framework Assessment (RFA) described in paragraph 8.1, has recommended a 10 year minimum closure period prior to transfer of all liabilities to the government. It is understood that this recommendation from the steering committee will fully incorporated into provincial law. The issue of 'climate liability', that is the cost of purchasing offset credits in the case of leakage from a storage site, are fully borne by the operator until the transfer of responsibility.

Another recommendation from the RFA steering committee, is that operators will have to provide a form of financial security to cover the possibility of project abandonment during the operational phase. The RFA does not specifically state whether the financial security should include an amount to cover climate liability during the operational phase. CCS project operators in Alberta also have the requirement to contribute to a Post Closure Stewardship Fund, based on a rate per tonne of CO_2 injected see paragraph 8.3. This fund is established to cover the assumed liability and monitoring obligations of the province once a closure certificate has been issued. The rate, which is yet to be established, will include a cost component for compensating any offset credits voided due to a leakage event. The RFA recommends using a risk and probability weighted basis for calculating such costs components.

Article 18 of the EU Directive on the geological storage of CO_2[40], states that a minimum period no shorter than 20 years must pass before the transfer of liability to the Member State can take place. However, this period could theoretically be reduced if the competent authority is convinced that the CO_2 is safely and permanently stored. The storage operator is fully liable for all elements of the project until the transfer of responsibility takes place. Prior to injection commencing, the operator must also provide a form of financial security, for updates of the monitoring plan, corrective measures, surrender of allowances under the EU Emissions Trading Scheme, premature site closure and temporary site operation by a third-party operator. Article 20 of the Directive, also requires that storage site operators provide a financial contribution to the competent authority to cover the costs of monitoring the closed site for a period of 30 years.

[39] Relevant costs are the capital and operational costs associated with deploying CCS.
[40] Directive 2009/31/EC

11 Conclusions

Since 2008, Alberta has established a comprehensive regulatory framework and effective funding programme to demonstrate CCS in the province. In comparison to the EU, it can be concluded that Alberta, and the Federal government of Canada have taken a more aggressive approach to financially supporting CCS projects. There are a number of key characteristics that distinguish the project selection procedure and the CCS funding programme operational in Alberta from the EU's EEPR and/or NER300:

- The overall total available funds committed per project in Alberta is greater than what has been made available in the EU.
- A maximum funding rate of 75% of relevant incremental costs is permitted in Alberta, compared to 50% of the relevant costs permitted in the EU's NER300.
- Alberta's CCS funding programme allows for 40% funding to be provided during the construction phase, whereas the NER300 utilises an annual performance payment, requiring the potential project operator to risk significant capital investment.
- The type of CCS projects chosen in Alberta, high-purity CO_2 sources from hydrogen production, are technically less challenging and less energy intensive than the projects chosen for the EEPR, which involve first-of-a-kind post combustion and oxyfuel power generation installations.

In addition to the funding specific characteristics, the decision to utilize CO_2 for the purposes of enhanced oil recovery, provides an additional level of income to offset the costs of CCS projects. The certainty of the compliance requirements with the Specified Gas Emitters Regulation, the fixed $15 (€10) per tonne CO_2 fee, and the governments signal to increase this 2014, represents an important policy incentive. Having a fixed price on carbon may provide CCS project investors with more uncertainty that a market-based mechanism such as the EU ETS.

Regarding the regulatory framework for CCS, it cannot be concluded that either the Albertan or European framework places greater demands on the operator in terms of financial security requirements or exposure to liability. The Albertan RFA steering committee recommends a minimum 10 year closure period prior to the transfer of all liabilities to the government, whereas the EU Directive on the geological storage of CO_2 states a minimum of 20 years, but tolerates Member State discretion to shorten this period. The certainty of having a 10 year period could be considered an advantage in terms of risk management and investor confidence. As the Albertan regulatory framework has yet to be tested to its full extent, the financial obligations for project operators associated with the financial security for orphaned infrastructure and the rate set for the Post Closure Stewardship Fund cannot yet be commented on. These obligations should become apparent over the course of 2014.

12 References

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