TOWARDS A STRATEGY FOR IMPLEMENTING CO_2 CAPTURE AND STORAGE IN CANADA

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Executive Summary

The possibility of using CO_2 capture and storage (CCS) technologies to achieve deep reductions in emissions from electric power generation has recently become salient in Canadian climate policy. I argue for a cautious approach. While there are good reasons to expect that CCS will eventually enable deep reductions in CO_2 emissions both in the electric sector and elsewhere in the economy, it is—with one exception—unwise to aim for substantial adoption of CCS in the Kyoto commitment period (2008–2012). Government action to force implementation would be unwise, because rapid implementation of CCS would drive up costs and because important issues surrounding the risks, regulation, and public perception of CCS are unresolved.

The exception is in the oil and gas (O&G) sector, where there is an opportunity to use CCS to achieve significant emissions reductions within the Kyoto time frame. The cost of capturing CO_2 and injecting it into geological reservoirs is strongly dependent on the size and purity of the CO_2 stream. Combustion sources have CO_2 concentrations of 5–15%; for these dilute streams, the cost of capturing CO_2 dominates the cost of storage. The cost of capture is smaller for non-combustion sources and can be zero for high-pressure sources of nearly pure CO_2. In Canada, the most important non-combustion sources of CO_2 are natural gas processing and the production of hydrogen (H_2) used in petroleum refining.

Raw natural gas contains significant CO_2, most of which is removed at gas processing plants prior to delivery to consumers. Some of this natural-gas-associated CO_2 (NG-CO_2) is now injected into geological storage reservoirs as a side effect of sour gas processing. This process provides important practical experience with CO_2 storage and is an area of Canadian expertise. This technology could be extended to capture a significant fraction of the NG-CO_2 stream at low cost. Total NG-CO_2 production is about 9 Mt-CO_2/year. If gas production rises as forecast, it will likely rise to at least 13 Mt-CO_2/year by 2010, equivalent to 2.4% of Canada's CO_2 emissions.

The upgrading of raw bitumen extracted from the oil sands to produce synthetic crude oil requires large amounts of hydrogen. Almost all the required hydrogen is produced from natural gas using a process that can produce a stream of nearly pure CO_2 containing most of the carbon in the initial natural gas stream. Unfortunately, the newest hydrogen plants use a process that does not produce a pure CO_2 stream, so implementing CO_2 capture would require modification of plants now being planned or retrofit of plants that are already built. The construction of hydrogen plants to meet the demands of bitumen upgrading in Alberta may soon produce the world's largest concentration of hydrogen production facilities. The quantity of CO_2 potentially available from hydrogen production may well exceed 10 Mt-CO_2/year by 2010.

Technological capability is a necessary but insufficient condition for CCS to play a major role in mitigating CO_2 emissions. To fulfil its promise, CCS must evolve from a collection of individual technologies into a large-scale technological system for managing fossil fuel carbon. Such a system will require a suite of technologies linked by a network of institutions, financial systems, and regulations that are able to achieve public understanding and acceptance.

Uncertainty in the effectiveness of CO_2 storage, arising from uncertainty in the lifetime of stored CO_2, is not currently addressed by any Canadian government entities. It will need to be. Although management of geological resources is a provincial responsibility, the management of CO_2 stored to avoid atmospheric emissions implies a federal responsibility because it arises from international commitments to control emissions. The international status of CO_2 storage is

unclear. While both the Kyoto Protocol and the recent Conferences of the Parties in Bonn and Marrakech explicitly endorse the use of CO_2 storage, crucial questions regarding the incorporation of CO_2 storage within the accounting rules of the United Nations Framework Convention on Climate Change remain to be decided.

The difficulty in building a system for regulating CO_2 storage is not simply due to technical uncertainty in predicting the lifetime of stored CO_2; it also arises from uncertainty about the goals of storage. Should the median lifetime of CO_2 in storage facilities be 500 years or 10 000? What fraction of early failures are we willing to accept? Uncertainty in predicting the fate of CO_2 in reservoirs cannot be eliminated. The regulatory system cannot therefore demand zero risk. The challenge is to build a regulatory regime that works despite these uncertainties.

Efforts to build a robust regulatory environment for geological storage cannot wait until the technology is ready for large-scale application. Environmental regulators, industry, and environmental groups need to begin to build a common understanding of the current state and future course of regulation, identifying areas of common concern and developing compromises to address areas of disagreement. The federal government must assume a central role in managing this effort.

Wherever it is introduced, CO_2 storage is certain to generate public controversy. This controversy will arise from specific concerns about the safety of storage and more general concerns about sustainability. In contrast to the electric sector, the early introduction of CCS in the O&G sector will likely focus debate on the safety and longevity of CO_2 storage, rather than on the choice between fossil and non-fossil primary energy. While both concerns are legitimate, debate centred on the former will be more likely to resolve key questions about the acceptability of CCS technologies.

Government action to encourage the adoption of CCS technologies in the O&G sector could yield significant, low-cost reductions in CO_2 emissions within the Kyoto commitment period while building the institutional and technological capacity necessary for broader use of CCS in the future. Specifically, I estimate that emissions could be reduced—compared with business as usual—by about 20 Mt-CO_2/year at an average cost[1] of \$15–25/t-CO_2. The rapid growth in the O&G sector would lower the cost of emissions mitigation, because CCS could be built into new facilities where costs are generally lower, rather than added to existing systems where costs would be higher. If action is delayed, much of this opportunity for low-cost mitigation will be lost.

[1] All monetary figures in this report have been expressed in year 2000 Canadian dollars unless otherwise indicated.

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Acronyms, Abbreviations, and Units

AGI	Acid gas injection
AMG	Analysis and Modelling Group
bbl	Barrel
CCS	CO_2 capture and storage
CO	Carbon monoxide
CO_2	Carbon dioxide
ENGO	Environmental non-governmental organization
EOR	Enhanced oil recovery
EUB	Alberta Energy and Utilities Board
FGD&SCR	Flue gas desulphurization and selective catalytic reduction
GDP	Gross domestic product
GHG	Greenhouse gas
Gt	Gigatonne
H_2	Hydrogen
H_2-CO_2	Hydrogen-associated CO_2
H_2S	Hydrogen sulfide
IGCC	Integrated gasification combined cycle
IPCC	Intergovernmental Panel on Climate Change
kg-CO_2	Kilogram of CO_2
km	Kilometre
kPa	Kilopascal
kt-CO_2	Kilotonne of CO_2
kW	Kilowatt
kWh	Kilowatt-hour
Mt	Megatonne
Mt-CO_2	Megatonne of CO_2
MWh	Megawatt-hour
NGCC	Natural gas combined cycle
NG-CCS	Natural-gas-fired CCS
NG-CO_2	Natural-gas-associated CO_2
NO_x	Nitrogen oxides
O&G	Oil and gas
PC	Pulverized coal
$PM_{2.5}$	Particulate matter less than or equal to 2.5 microns in diameter
ppmv	Part per million by volume
PSA	Pressure swing absorption
R&D	Research and development
scf	Standard cubic feet
SMR	Steam methane reforming

SO_2	Sulphur dioxide
SO_x	Sulphur oxides
t-C	Tonne of carbon
Tcf	Trillion (10^{12}) cubic feet
t-CO_2	Tonne of CO_2
UN-FCCC	United Nations Framework Convention on Climate Change

1. Introduction

Canada stands at the threshold of commitment to costly action aimed at reducing emissions of greenhouse gases (GHGs), principally CO_2. Canada has made international commitments to reduce emissions under the United Nations Framework Convention on Climate Change (UN-FCCC) and the Kyoto Protocol, and the federal government has recently begun to allocate significant resources to mitigating emissions with programs such as Action Plan 2000. Climate policy is nevertheless at a threshold, with crucial questions about the magnitude, timing, and character of the policy measures remaining unresolved. The current commitment of funding is far less than would be required to fulfil the intent of the Kyoto agreement, which was to reduce emissions to an average of 94% of their 1990 levels during the 2008–2012 period. The level of public and governmental support for sustained and costly action is, at best, uncertain. Moreover, there is little agreement about the kinds of measures that should be used to reduce emissions or about the appropriate distribution of economic pain across sectors of the economy. Uncertainty is further compounded by the ambiguity of the international climate policy regime. Put most bluntly, it is still possible—depending on the detailed rules adopted for carbon trading and assuming continued U.S. abstention—that the formal terms of the Kyoto Protocol could be met at very modest cost and with little environmental benefit [1].

It has long been assumed that reductions in CO_2 emissions will be achieved through a combination of increasing the efficiency of energy use and switching to non-fossil sources of primary energy, such as renewables or nuclear. Over the last decade, a new option has emerged: the use of fossil fuels with minimal atmospheric emissions of CO_2, accomplished by capturing the carbon content of fossil fuels while generating carbon-free energy products, such as electricity and hydrogen, and storing the resulting CO_2 away from the atmosphere (Figure 1). Although many of the component technologies necessary for CO_2 capture and storage (CCS) currently exist at large scale, the idea that CCS could play a central role in our energy future is a radical break with recent thinking about energy system responses to the climate problem.

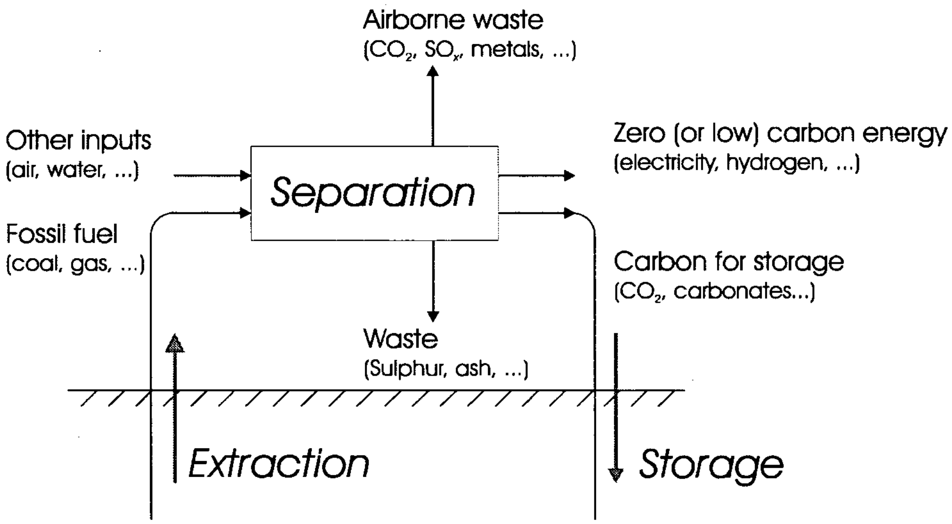

Figure 1. CO_2 capture and storage viewed as a general process for using fossil fuels with minimal atmospheric emissions of CO_2.

While CCS is best viewed as just one element in a broad portfolio of GHG mitigation technologies, it may nevertheless transform the politics of the CO_2–climate problem. By lowering the cost of emissions mitigation, CCS may enable stabilization of atmospheric concentrations at acceptable cost. By weakening the link between fossil energy and atmospheric CO_2 emissions, CCS makes it feasible to consider a fossil-fuelled global economy through the next century. By reducing the severity of the threat that emissions reduction poses to fossil energy industries and fossil-energy-rich nations, CCS may ease current deadlocks in both domestic and international climate policy.

There are, however, no magic bullets with which to slay the CO_2–climate problem. All current energy supply options that might be used to make deep cuts in CO_2 emissions either are impractically expensive (solar) or pose significant environmental challenges (wind, biomass, CCS, and nuclear). Moreover, global energy systems are highly heterogeneous, making it implausible that any single technology will triumph everywhere. Finally, the history of energy policy is replete with technologies that their advocates advanced as being too cheap to meter, yet which are now irrelevant. Thus, while I paint an optimistic picture about the potential role of CCS in mitigating CO_2 emissions, skepticism is in order. The very fact that CCS was not on the energy policy agenda even a decade ago should make one cautious about any predictions for the next century.

1.1 Scope and Purpose of the Report

This report examines the opportunity for implementing CCS in Canada, focusing on the next 10–15 years. I do not aim to provide a comprehensive treatment or precise estimates of the cost of mitigating CO_2 emissions. Instead, I focus on strategic questions:

- What industrial sectors provide the best opportunities for implementing CCS, and what policy instruments might best promote implementation?
- What are Canada's strategic assets and liabilities in implementing CCS?
- How does CCS couple the control of CO_2 and conventional pollutants?
- What are the risks of CCS, and what options exist to manage and regulate them?
- What are the specific roles for Environment Canada?

The possibility of using CCS technologies to enable deep reductions (50%) in CO_2 emissions from Canada's electric sector has recently become salient in Canadian climate policy. I argue for a cautious approach. While there are good reasons to expect that CCS could eventually enable deep reductions in CO_2 emissions both in the electric sector and elsewhere in the economy, it is—with one exception—unwise to aim for substantial adoption of CCS in the Kyoto commitment period (2008–2012). Government action to force substantial implementation by 2008–2012 would be unwise, both because rapid implementation of CCS would drive up costs and so provide economically inefficient mitigation of CO_2 emissions and because important issues surrounding the risks, regulation, and public perception of CCS are unresolved. Overly rapid government action to force adoption of CCS might well produce a public backlash that would frustrate attempts to implement economically efficient measures for mitigating CO_2 emissions.

That exception is the application of CCS to reduce emissions from non-combustion sources of CO_2 in the upstream oil and gas (O&G) sector. A number of technological and institutional factors suggest that significant implementation of CCS could be achieved in this sector at moderate cost within the Kyoto commitment period.

The remainder of the report is organized as follows. Section 2 surveys the opportunities for implementing CCS in Canada, focusing on its application in two sectors, electric power and O&G. It addresses the technology and economics of CO_2 mitigation, while deferring questions of policy and implementation to Section 4. The risks of CCS are surveyed in Section 3, as is the challenge of successfully managing the risks through regulation. Section 4 addresses the strategic challenges of implementation, comparing the opportunities in electric power generation and O&G and analyzing some specific policy instruments that might be used to encourage implementation. Finally, Section 5 reviews the specific roles for Environment Canada in managing CCS.

2. CO_2 Capture and Storage in Canada: Opportunity,Technology, and Economics

Most analysis of CCS has focused on its application to centralized electricity generation, where the technology could enable deep reductions in CO_2 emissions with minimal reorganization of the electricity distribution infrastructure. While the electric sector is an important arena for CCS, the technologies could eventually be applied more broadly to mitigate CO_2 emissions throughout the economy (see Figure 1).

The technology can, for example, be used to produce hydrogen from fossil fuels without CO_2 emissions. The use of hydrogen as an energy carrier could enable deep reductions in CO_2 emissions via the substitution of hydrogen for natural gas or gasoline in buildings and transportation, respectively. Hydrogen can be produced from many primary energy sources; if hydrogen is widely used, however, fossil fuels with CCS will likely be the dominant source, because the intrinsic cost advantage of CCS over other low-CO_2-emission technologies is particularly strong for hydrogen production.[2] In the long run, if CCS makes sense anywhere, it makes sense for hydrogen production. Achieving significant emissions reductions using hydrogen, however, will require the development of a large-scale infrastructure for hydrogen distribution and use [4]—a very difficult and uncertain venture. Because of these structural barriers, hydrogen will not likely play a significant role as an energy carrier for many decades.

Although the great majority of CO_2 emissions arise from combustion, significant non-combustion sources of CO_2 exist for which the cost of capture and storage is comparatively low. These niche applications of CCS provide opportunities for near-term reductions in CO_2 emissions while simultaneously providing invaluable institutional and technological experience with capture and storage. In Canada, the largest concentrated non-combustion sources arise from O&G production and processing.

The various potential applications of CCS may be ordered by their expected mitigation costs[3] or by the difficulty of surmounting the structural barriers that bar their implementation. Either ordering would put non-combustion sources first, electric power generation second, and large-

[2] Like electricity, hydrogen is an energy carrier that must ultimately be generated from some primary energy source. The cost advantage of fossil fuels with CCS over solar, wind, or nuclear power is considerably larger for hydrogen production than it is for electricity because of the relative ease of thermochemical conversion (fuel to hydrogen) compared with electrochemical conversion (electricity to hydrogen) and also because solar and wind power produce electricity, which must then be converted to hydrogen [2,3].

[3] As used here, the "mitigation cost" of a technology is the cost of reducing CO_2 emissions using that technology assuming constant factor prices. This is equivalent to the carbon price at which the technology would provide the same services at the same cost as some baseline technology.

scale use of hydrogen third, as CCS offers the most costly and difficult-to-implement path to emissions mitigation. This report assesses the strategy for implementation of CCS in Canada over the next 10–15 years; it therefore largely ignores opportunities for use of hydrogen as an energy carrier and instead focuses on the electric power sector and on the O&G sector, from resource extraction through refining.

2.1 Electric Power Generation

Electric power generation emits ~100 Mt-CO_2/year, about 19% of Canada's CO_2 emissions. Several recent government studies have suggested that CCS could be implemented to achieve deep reductions (~40%) in emissions from the electric sector, providing an important contribution to meeting Canada's commitments under the Kyoto Protocol [5,6].

Several lines of argument support the idea that CCS might find comparatively early application in electric power generation. First, there are at least four general reasons why electric power generation will likely bear a disproportionate share of the burden of reducing CO_2 emissions over the next few decades:

1. Electric power plants are among the largest point sources of CO_2.

2. Deep reductions in emissions can be achieved without requiring system-wide changes in distribution and end-use equipment, as would be required to achieve similar reductions in other sectors.

3. Most coal is used for electric power generation, and coal has the highest carbon-to-energy ratio of the fossil fuels. Moreover, coal combustion is a significant source of conventional air pollution.

4. The centralization of capital and management in electric power generation makes regulatory implementation simpler than for other end-use sectors.

Second, there are reasons to expect that if deep emissions reductions are demanded in the electric sector, then structural factors may make CCS play a larger role than is suggested by its cost alone. Given open competition between electricity technologies under a carbon tax (or economically equivalent regulatory mechanism), and assuming that carbon storage can meet environmental permitting requirements, CCS may be adopted in preference to non-fossil alternatives, even if their electricity costs are similar. Unlike wind power, for example, CCS plants would match the existing distribution system with respect to sizing and ease of dispatch.[4] Moreover, CCS plants will likely be constructed using existing suppliers, and established upstream fossil energy companies could provide both fuel and CO_2 storage. While nuclear power could, in principle, play a central role in reducing CO_2 emissions, absent sweeping changes in the industry, its regulation, and its public perception, it seems likely that utilities will find CCS less risky and less expensive than nuclear power.

As the capstone of the economic analysis performed by the National Climate Change Process, the Analysis and Modelling Group (AMG) report was perhaps most influential in building

[4] "Dispatch" refers to the adjustment of power plant output to meet varying demand. At good sites, wind can produce electricity at low cost—compared with other low-emission technologies—but this understates the cost of large-scale wind-generated electricity, because additional storage, backup, or transmission would be required in order for wind to supply a substantial fraction of system demand.

expectations that CCS could be widely deployed in the electric sector to meet Canada's Kyoto commitment. Specifically, the baseline assumption of the AMG report[5] is that 42 Mt-CO_2/year could be captured at a price of \$38/t-CO_2. The 42 Mt-CO_2/year was derived by assuming that CCS could be applied to most coal-fired electric capacity located in the Western Canadian Sedimentary Basin. While cost assumptions originated in the Electricity Issues Table, it seems likely that inclusion of CCS in the AMG report played an important role in raising the profile of CO_2 capture technologies in federal and provincial governments.

Notwithstanding the long-term importance of CCS for mitigating emissions from electric power generation in Canada, a policy that forced rapid implementation of CCS—such as the scenarios analyzed in the AMG report—would be both unrealistic and unwise. The wisdom of such a policy is the subject of Section 4.1.2; here, I focus on assessing factors that control the rate at which CCS technologies could be implemented and on the cost of avoiding CO_2 emissions.

2.1.1 Rate of Implementation

In order to capture an average of 42 Mt-CO_2/year over the 2008–2012 period, it is necessary either to have all plants in operation by 2008—six years away—or to increase the amount of CO_2 captured later in the commitment period. An elapsed time of six years from project initiation to first operation is a respectable period for building modern pulverized-coal (PC) plants; in Canada, the time may now be as short as 5 years.[6] It would take significantly longer to built a CO_2 capture plant, particularly one using new technology. Meeting the AMG reduction target would thus require the immediate initiation of planning for all required plants—a highly implausible scenario.

It is marginally more plausible that retrofits could be completed within this time frame; however, since retrofits using current amine technology[7] derate plant output by ~25%, this course would nevertheless require major construction of new capacity to make up for plant derating. Achieving the AMG goal is therefore unrealistic, because the required rate of implementation would be very hard to achieve.

If it were, in fact, necessary to replace all coal-fired electric power generation in Alberta and Saskatchewan with zero-CO_2-emission technology by 2008, it would be easier, and far less risky, to use natural-gas-fired systems. For new plants, natural-gas-fired CCS (NG-CCS) systems are directly competitive with coal-CCS (Figure 2). The overall costs of electricity from the two systems are roughly equal within uncertainties, which are dominated by the uncertainty of future gas prices and by the cost of CO_2 storage[8] [7, 8, 9, p. 256]. While the overall electricity costs are

[5] The AMG defined various scenarios ("paths"). Paths 1 and 3 assumed that each economic sector contributed equally to emissions reductions; these assumptions produced higher overall costs and resulted in little use of CCS, because electric sector emissions mitigation was modest. Paths 2 and 4 allowed trading between sectors to reduce the overall cost of meeting the Kyoto target, resulting in large reductions in electric sector emissions and an average (between the two paths) of 42 Mt-CO_2/year of emissions reductions achieved through CCS [5, p. 81].

[6] The total time for a generic PC plant would be about 5 years, about 1½ for design planning and permitting and about 3½ for construction (personal communication, Malcolm McDonald, Director Research and Technology, TransAlta, November 2001).

[7] If retrofits had to be operational by 2008, there would likely be insufficient time to develop improved capture technology.

[8] The cost of avoided CO_2 emissions for NG-CCS, as it is conventionally calculated, is roughly twice that for coal-CCS, because the baseline natural gas combined cycle (NGCC) plant has ~50% lower emissions

roughly equal, the capital cost of NG-CCS generation is about two-thirds that of coal-CCS, technical uncertainties are smaller, and permitting and construction would be considerably faster.

2.1.2 Cost of CO_2 Mitigation

Published estimates of the cost of reducing CO_2 emissions from electric generation via CCS vary by almost an order of magnitude; the variance in cost estimates, however, greatly overstates the technical uncertainty. Part of the variance arises from unavoidable uncertainties in assessing the cost and performance of unproven technologies, but additional variance arises from inconsistencies in analytical assumptions that exaggerate the technological uncertainty. Inconsistency arises in three ways:

1. *Choice of reference case.* Analysts often estimate the cost of avoiding CO_2 emissions expressed in \$/t-C, but any such estimate necessarily depends not only on the cost and performance of the CCS technology, but also on the specification of a reference case with a specific energy cost and CO_2 emissions per unit electricity. Estimates of the cost of generating electricity with CCS—which depend on factors specific to the plant (such as thermal efficiency)—are therefore more robust than estimates of the cost of avoiding emissions—which depend on the electric power market in which the power plant operates.[9] The multipollutant issues discussed in Section 4.3.1, for example, arise because the performance of the reference plant depends on the assumed controls on conventional air pollutants.

2. *Economic assumptions.* Most obviously, studies may use inconsistent economic assumptions for key parameters such as discount rates, fuel costs, capacity factors, and the costs of CO_2 storage.

3. *Timing.* Engineering studies have used widely differing assumptions about the availability of new technologies, with some estimating the cost of a plant that could be ordered today with performance guarantees and others estimating the cost of novel plant configurations or plants that require components that do not yet exist commercially.

Even when all such inconsistencies are resolved, the variance of results between engineering studies is larger than the uncertainty about the cost and performance of a plant that would actually be built, since the design of such a plant would be chosen to minimize cost (along with other factors such as risk). This is the case because engineering studies generally evaluate the performance of a particular design, and some of their variance reflects emerging knowledge about which plant configurations are best, rather than technical uncertainty about the performance of an optimal plant.

Finally, government action that forces the adoption of environmental controls will likely encourage innovation, which reduces the cost of control. The policy implications of this induced technological change are the subject of Section 4.3.2. The history of sulphur controls on electric power plants provides an important example of induced change. Between the late 1970s and

than the baseline PC plant. But what matters for electric utility planners (or investors) is the overall cost of generation under a carbon price that is roughly the same for the two systems.

[9] Robust estimates of the cost of mitigation require analysis that captures the trade-offs between various generating technologies and fuels (e.g., gas vs. coal), both on the short timescales on which plants are dispatched to meet demand and on the longer timescale on which installed capacity changes in response to restrictions on emissions.

1995, the capital cost of SO_x controls decreased from US$250 to US$125/kW of capacity while the average removal efficiency increased from about 75% to 95%, and there is strong evidence to suggest that the primary driver of cost declines was the imposition of government controls on sulphur emissions [10]. While it is not possible to accurately predict how the cost of CCS technologies will respond to controls on CO_2 emissions, there is no doubt that future costs depend not just on R&D, but also—and perhaps more importantly—on experience with the technology in commercial operation.

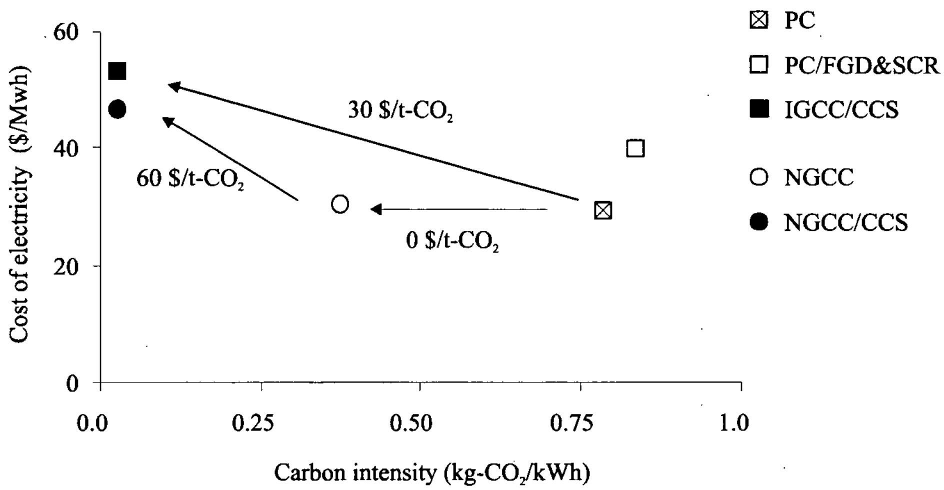

Figure 2. The cost of electricity versus CO_2 emissions per unit of output. Costs (in U.S. funds) are representative of current estimates but are, of course, strongly dependent on assumptions about fuel price and the cost and performance of CCS technologies. With these assumptions, the mitigation cost of coal-to-gas fuel switching is zero for new plants, while the mitigation cost of CCS is ~US$30/t-$CO_2$ and ~US$60/t-$CO_2$ for coal and gas, respectively. Note that this is true despite the fact that NG-CCS provides cheaper electricity than coal-CCS. Note the differing costs and emissions intensities for coal plants with (PC/FGD&SCR) and without (PC) modern emissions controls, demonstrating that the cost of mitigation with CCS depends on the stringency of conventional pollutant control. Note: FGD&SCR is flue gas desulphurization and selective catalytic reduction; and IGCC is integrated gasification combined cycle.

Timing is crucial in assessing the cost of CCS. It is quite plausible that CCS could enable deep reductions in CO_2 emissions from electricity generation at a cost of under $30/t-$CO_2$ if the reductions do not need to be fully implemented until 2015 and if a sustained program to encourage R&D and demonstration projects is begun soon. Conversely, if deep reductions are required by 2008, then it is very unlikely that mitigation costs could be as low as $38/t-$CO_2$ (as assumed in the AMG analysis).

2.2 Oil and Gas

The cost of capturing CO_2 and compressing it to the pressures required for geological storage (typically greater than 10 000 kPa, or 100 atmospheres) is primarily dependent on the size and purity of the CO_2 stream to be captured. Combustion sources have CO_2 concentrations of 5–15%; for these dilute streams, the cost of capturing CO_2 dominates the cost of storage, accounting for perhaps three-quarters of the overall cost of CCS [2, 7]. The cost of capture is smaller for non-combustion sources and can be zero for high-pressure sources of nearly pure CO_2. In Canada, the two most important non-combustion sources of CO_2 are natural gas processing and hydrogen production; these sources in turn provide the most important opportunities for applying CCS technologies in the O&G sector.

2.2.1 Natural-Gas-Associated CO_2

Raw natural gas may contain significant impurities, with CO_2, H_2S, and nitrogen being the most important. One may consider all of the CO_2 that is produced from wells along with natural gas as a single stream of non-combustion CO_2 to be managed (Figure 3). I call this stream natural-gas-associated CO_2 (NG-CO_2). Much of the CO_2 and virtually all the H_2S are removed at gas processing plants prior to delivery to the final consumer.[10] At present, almost all of the NG-CO_2 is eventually emitted to the atmosphere, either at gas processing facilities or at the point of final combustion. Although emissions of NG-CO_2 amount to only a few percent of the CO_2 emissions that arise from combustion of the natural gas, they nevertheless provide an important opportunity for mitigating Canada's CO_2 emissions and for gaining experience with CCS.

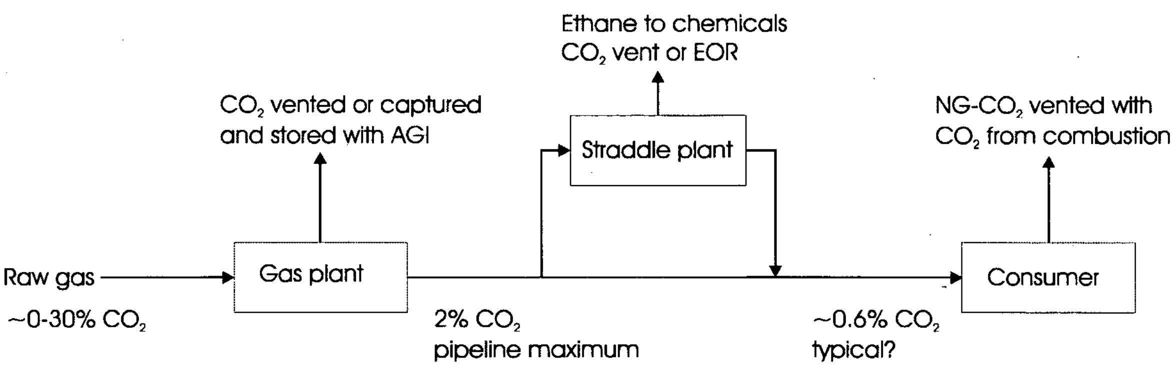

Figure 3. A schematic illustration of the natural gas processing system. Note: AGI is acid gas injection and EOR is enhanced oil recovery.

The mean CO_2 concentration of natural gas produced in Canada is currently about 2.5%, implying that the total production of NG-CO_2 is currently about 9 Mt-CO_2/year, equivalent to 1.5% of Canadian CO_2 emissions.[11] Gas production is forecast to rise by about 50% in the next decade—about half its rate of growth during the 1990s—likely bringing NG-CO_2 production to ~13 Mt-CO_2/year by 2010. At this level, NG-CO_2 would amount to 2.4% of Canada's CO_2 emissions in 2010; if these emissions could be eliminated, they would be about 12% of the CO_2 emissions reductions necessary to meet Canada's Kyoto target.[12] Moreover, the average CO_2 content of produced gas may well rise as gas production moves to deeper reservoirs in the northwest of the Alberta basin and elsewhere in the northern Rockies. Such an increase in CO_2 content might be driven by depletion of the least contaminated (sweet gas) reserves, coupled with declines in the costs of accessing deep gas and processing sour gas. If gas production continues to rise steeply—driven in part by coal-to-gas fuel switching in a CO_2-constrained electric power

[10] Gas sold for distribution to consumers, "sales gas," can contain up to 2% CO_2 and a maximum of 16 ppmv H_2S (4 ppmv in the United States).

[11] I assume that year 2000 natural gas production was 180 billion m^3 (6.4 Tcf) at an average CO_2 concentration of 2.5% (see discussion in the next section).

[12] Using figures from the 1997 emissions inventory and assuming that future emissions and emissions reductions ("the gap") maintain the current relative contributions from the various GHGs.

sector—and if the average CO_2 content rises over 3.5%, then NG-CO_2 production could easily exceed 20 Mt-CO_2/year near the end of the Kyoto commitment period.[13]

The mitigation of NG-CO_2 emissions by capture and geological storage can build directly on industry experience with the disposal of CO_2 plus H_2S (acid gas) mixtures arising from sour gas processing.[14] The least costly method to eliminate H_2S is to flare the acid gas stream, burning the H_2S to SO_2 and releasing the CO_2 to the atmosphere. Over recent decades, concern for the environmental effects of sulphur emissions has eliminated flaring as an option for all but the smallest facilities. In response to restrictions on flaring, gas processors switched to sulphur recovery, which produces sulphur as a saleable by-product but releases the CO_2 as before. In response to falling sulphur prices and increasingly stringent restrictions on residual SO_2 emissions, the industry has recently begun to abandon sulphur recovery in favour of acid gas disposal. For the largest plants, the lowest-cost route may still be sulphur recovery, but for plants with lower H_2S fluxes, the lowest-cost option is to compress the full acid gas stream (CO_2 and H_2S) and dispose of it in a suitable geological formation [11]. This process, called acid gas injection (AGI), is practised in over 31 facilities in Canada and at a rapidly growing number in the United States. For existing AGI facilities, CO_2 mitigation has been achieved at a negative cost, in the sense that AGI is the lowest-cost treatment for acid gas, cheaper than alternatives that would release the CO_2.

Industry experience with AGI provides a technical foundation that could be expanded to achieve the capture and storage of a substantial fraction of the NG-CO_2 stream. In addition, AGI provides important regulatory experience with CO_2 storage, as discussed in Section 3.2. The path from AGI to broader efforts to capture NG-CO_2 will likely involve the following key technological steps:

1. Implementing AGI rather than sulphur recovery for new sour gas facilities. (For small H_2S flows, AGI is already the least costly method, but for the largest facilities, sulphur recovery may still be cheaper.)

2. Converting existing sour gas plants from sulphur recovery to AGI.

3. Implementing CO_2 compression and geological storage from plants that process high-CO_2/low-H_2S gas and currently vent the CO_2.

4. Increasing the CO_2 capture from straddle plants by capturing existing CO_2 streams and modifying processes to increase CO_2 capture.

Finally, there are likely important opportunities to reduce the cost of mitigating NG-CO_2 emissions by optimization across the gas processing system. It might, for example, be efficient to decrease CO_2 capture at some upstream gas plants and increase capture at straddle plants to take full advantage of economies of scale in capture and storage.
Compared with other sectors, the mitigation supply curve for NG-CO_2 is particularly hard to estimate accurately because of the rapid pace of change in the natural gas industry. Principal

[13] A production rate of 285 billion m^3 (10 Tcf) and 3.5% CO_2 implies 20 Mt-CO_2/year. This production rate is ~50% higher than current (2000) production.

[14] A gas stream that contains more than 16 ppmv H_2S must be processed to remove the H_2S. Such processing typically uses amine temperature swing absorption, which captures most of the CO_2 in addition to the H_2S. The resulting CO_2 plus H_2S (acid gas) stream must then be processed to eliminate H_2S.

sources of uncertainty are (i) estimates of future gas composition and production volume, (ii) estimates of the disposition of NG-CO_2 in the absence of incentives to mitigate CO_2 emissions, and (iii) the engineering cost of additional CO_2 capture technologies.

While rapid change in the natural gas industry makes accurate estimates of mitigation cost more difficult, it likely decreases the cost of mitigation, because it allows CO_2 capture to be built into new facilities where costs are generally lower, rather than added to the existing system where costs will be higher and process optimization more difficult to achieve.

It seems plausible that 10 Mt-CO_2/year (two-thirds of the likely total amount of NG-CO_2) could be captured and sequestered at an average cost of about \$20/t-CO_2, assuming (i) continued rapid growth in gas production, (ii) increasingly stringent controls on SO_2 emissions, and (iii) early government action that allows industry to take advantage of the cost reductions that arise from building CO_2 capture into the gas processing infrastructure.

2.2.2 CO_2 from Hydrogen Production

Hydrogen is used in petroleum refining to efficiently produce lighter (lower-molecular-weight) products via hydro-cracking and for desulphurization. The upgrading of raw bitumen extracted from the oil sands to produce synthetic crude oil requires particularly large amounts of hydrogen, about 1000 scf-H_2/bbl of synthetic crude oil. When the hydrogen required for upgrading is combined with the hydrogen required for refining, the total amount of hydrogen required to produce refined petroleum products from the oil sands bitumen is 5–10 times larger than it is from conventional crude oil.[15] Almost all the required hydrogen is produced from natural gas via steam methane reforming (SMR), a process that can produce a stream of nearly pure CO_2 containing most of the carbon in the initial natural gas stream.

As oil sands production expands rapidly, so will production of hydrogen. The construction of hydrogen plants to meet the demands of bitumen upgrading in Alberta may soon produce the world's largest concentration of hydrogen production facilities. Industry estimates suggest that an average of more than one large (100 million scf/day) hydrogen plant will be built each year this decade, raising total capacity to roughly 2 billion scf/day,[16] about four times the current level, a capacity equivalent to about 20% of current world production of hydrogen for refining. This rapid development of hydrogen capacity presents an important opportunity for implementing CCS to mitigate the CO_2 emissions associated with hydrogen production (H_2-CO_2).

Conventional hydrogen production using SMR and water-gas shift produces 3.5–4 volumes of hydrogen for each volume of CO_2. A hydrogen production of 2 billion scf/day would therefore result in about 500 million scf-CO_2/day, or 13 Mt-CO_2/year. Because the largest uncertainty in estimating the potential CO_2 production lies in predicting the future rate of synthetic crude production, it is perhaps most useful to estimate the ratio of H_2-CO_2 production to the output of synthetic crude; that ratio is about 5 Mt-CO_2/year for each million bbl/day of synthetic crude.

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[15] For comparison, hydrogen consumption in typical refining is 100–200 scf-H_2/bbl crude. Hydrogen consumption in California to produce reformulated gasoline is considered very high at about 600 scf-H_2/bbl crude (all values exclude the by-product hydrogen from naphtha reforming). The 1000 scf-H_2/bbl for upgrading bitumen is to produce synthetic crude; still more hydrogen is needed to produce derived products.
[16] Personal communication, Tom McCann, T.J. McCann and Associates Ltd., Calgary, October 2001. This estimate was derived by compiling a list of the hydrogen production facilities under construction or in the planning process and applying a rough discount to account for plants that will not go ahead.

Two obstacles frustrate the immediate application of CCS technologies to H_2-CO_2: first, changes in hydrogen production technology that are eliminating the pure CO_2 streams, and second, the location of most upgrading at Fort McMurray, which is 200–400 km from good geological storage sites near the mountain front.

Older hydrogen plants use SMR to produce syngas (mostly H_2 and CO) followed by water-gas shift reactors to produce a mixed hydrogen and CO_2 stream, which is separated, making high-concentration streams of hydrogen and CO_2. Newer plants use pressure swing absorption (PSA) to remove hydrogen from the syngas stream and reduce the efficiency of the water-gas shift step to exploit the advantages of integration with the refinery's fuel gas system. In these plants, the residual syngas stream (after hydrogen removal) is mixed with other fuel gases and then combusted as fuel. The combustion step in PSA systems eliminates the high-concentration CO_2 stream that was available in the older generation of hydrogen production plants.

Comparatively low-cost opportunities for capturing the non-combustion CO_2 from hydrogen production remain, but it is difficult to accurately assess the cost and quantity of CO_2 available because of (i) the integration of hydrogen production into other refinery processes, (ii) the rapid pace of technological change, and, perhaps most importantly, (iii) the difference in cost of CO_2 capture between retrofits of existing or soon-to-be-constructed plants and the cost from new hydrogen plants optimized to include integrated CO_2 capture.

There are three broad options for capturing CO_2 from hydrogen plants associated with bitumen upgrading:

1. *Retrofit the older non-PSA hydrogen plants*. Costs are dominated by the cost of compression. Depending on the desired CO_2 purity and final pressure, the cost is \$5–15/t-CO_2 [12].

2. *Retrofit the new PSA hydrogen plants*. Costs are likely in the \$15–25/t-CO_2 range if it is possible to capture the CO_2 from the high-pressure syngas stream. If such integration into plant operations is not possible, then the CO_2 must be captured from the combustion gases at significantly higher cost.

3. *Modify the design of new hydrogen plants to incorporate CO_2 capture*. A serious analysis effort is needed to understand the cost of avoiding CO_2 emissions in upgrading and refining operations. Cost will depend on the degree of integration with refinery operations. A significant amount of hydrogen production capacity is now in the planning process. For these plants, the available technical options and therefore the cost of CO_2 capture will be strongly dependent on the timing of a decision to capture CO_2. Previous estimates for the cost of CO_2 capture in PSA systems without fuel-gas integration range from \$13 to \$24/t-CO_2 [13, 14].

The second major barrier to reducing emissions of H_2-CO_2 using CCS technologies is the location of most of the hydrogen production at Fort McMurray, far from good sites for geological storage. Compared with the uncertainties associated with the capture of H_2-CO_2, however, the transport of CO_2 is well understood, and the development of a CO_2 pipeline could proceed rapidly once the source and disposition of the CO_2 were understood. Costs for transporting CO_2 at volumes above 5 Mt/year over the required distance are unlikely to be higher than \$10/t-CO_2. Some bitumen upgrading is now planned for the Edmonton area, with transport of bitumen from Fort McMurray to Edmonton accomplished via slurry pipeline. The presence of an economic incentive to reducing H_2-CO_2 emissions would add to the economic incentive favouring Edmonton-based upgrading facilities by reducing the cost of CO_2 transport.

3. Risks and Regulation

The technology required to inject large quantities of CO_2 into geological formations is well established. Industrial experience with CO_2 enhanced oil recovery (EOR) and with the disposal of CO_2-rich acid gas streams, together with related experience with natural gas storage and the underground disposal of other wastes,[17] allows confidence in predictions about the cost of CO_2 injection and suggests that the risks will be low. Once CO_2 is injected, evidence from natural CO_2 reservoirs as well as from numerical models suggests that it can—in principle—be confined in geological reservoirs for timescales well in excess of 1000 years, and that the risks of geological storage are small. Not withstanding this reasonable optimism, the risks of geological storage cannot be ignored. Indeed, a robust and inclusive risk assessment process will be needed to ensure the viability of CO_2 storage in Canada.

3.1 Risks

The risks associated with geological storage may be roughly divided into two kinds: first, the local health, safety, and environmental risks, and second, the global risk arising from leaks that return stored CO_2 to the atmosphere. The global risk may alternatively be viewed as uncertainty in the effectiveness of CO_2 storage.

3.1.1 Local Risks

The principal local risks arise from release of CO_2 at the surface, where it can asphyxiate exposed people or animals and can damage local biota. The most obvious local risk is the risk of catastrophic leaks such as well blowouts, pipeline ruptures, or subsurface events that result in sudden releases of CO_2. Catastrophic events can also be caused by slow leaks in deep CO_2 reservoirs if the CO_2 is temporarily confined in the near-surface environment and then suddenly released. In 1986, for example, the water in Lake Nyos (Cameroon) turned over, releasing about 100 kt-CO_2 that had accumulated from volcanic vents that had gradually charged the lake with CO_2. Because CO_2 is denser than air, it can flow downhill, creating asphyxiating conditions near ground level at points distant from the point of initial release. At Lake Nyos, the CO_2-rich cloud travelled over 10 km and killed over 1700 people [15].

While catastrophic releases have attracted the most attention, slow leaks may pose risks that are more difficult to manage. A leak of ~100 t-CO_2/day at Horseshoe Lake in California has killed trees over many hectares. A recent human fatality (July 2000) in a naturally occurring soda springs bath at Clear Lake, California, underlines the constant danger posed by CO_2 emissions from the ground.

The widespread use of natural gas storage facilities provides a useful analogue for assessing CO_2 storage, and the performance of natural gas storage points to the importance of slow leaks. In the summer of 2000, for example, the injection well of a gas storage facility in Hutcheson, Kansas,

[17] There is, for example, extensive experience with underground disposal in the United States. In addition to the ~34 Mt-CO_2 injected each year for EOR, the injection rates for other waste streams are 500 Mt/year for municipal wastewater, 2.7 Gt/year for brines from O&G operations, and 34 Mt/year for hazardous wastes.

leaked, allowing gas to flow into shallow formations, where it travelled approximately 10 km horizontally before erupting at many spots in the town site.

An entirely distinct class of local risks arises from the displacement of fluids during underground disposal. The injection of large volumes of fluids—equivalent to the volumes of CO_2 that would be stored over the lifetime of a coal-fired power plant—(i) may have induced seismicity, (ii) has produced ground movements that can cause structural damage to buildings and has obstructed the flow of irrigation water, and (iii) has caused the contamination of potable aquifers stemming from underground movement of displaced fluids.

Experts in the upstream O&G industry are generally confident that the risks from underground injection are small, and this confidence is strongly supported by the long history of underground disposal and specifically by the experience with CO_2 injection for EOR and AGI. While proper facility operation, site characterization, and monitoring can very likely reduce risks to low levels, they cannot be ignored.

3.1.2 The Uncertain Effectiveness of CO_2 Storage

We lack validated modelling tools that could enable confident predictions about the lifetime of CO_2 in underground storage. While there is ample reason to expect that sufficiently low leak rates can be achieved, it is not yet possible to specify with confidence the site characteristics and injection technology that are required to ensure (within some level of uncertainty) that a given confinement lifetime or leak rate will be attained. Such knowledge will be needed to build a robust technical and institutional system for storing CO_2.

In the worst case, the risk of CO_2 leakage is not simply that CCS will be ineffective, but that it will be detrimental. All CO_2 capture technologies extract an energy penalty, typically 10–20%. Thus, more fuel must be consumed, and more CO_2 produced, per unit of delivered energy than would be the case if the CO_2 were not captured. If CO_2 leaks to the atmosphere within centuries, CCS could therefore *increase* future concentrations of CO_2.

3.2 Regulation

Technological capability is a necessary but insufficient condition for CCS to play a major role in mitigating CO_2 emissions. To fulfil its promise, CCS must evolve from a collection of individual technologies into a large-scale technological system for managing fossil fuel carbon. In order to be successful, such a technological system must comprise a suite of technologies linked by a network of institutions, financial systems, and regulations that are accepted by industry and are able to achieve broad public understanding and acceptance.

What form those regulations assume, what entities are involved in project approval and ongoing oversight, how cooperative or adversarial the regulatory process is, and how many opportunities are presented for litigation and other third-party interventions will together be critically important in determining the economic attractiveness and social acceptance of CCS.

The regulation of a new activity does not usually arise in a vacuum, but is strongly shaped by the existing regulatory and institutional context. Regulation commonly builds by the accretion of new authority onto existing entities (such as government departments) as they battle with rival entities over resources. Efforts to build a robust regulatory environment for geological storage cannot wait until the technology is ready for large-scale application. Action is needed now to build understanding of the regulatory environment for geological storage in Canada. Such action might include the commissioning of studies aimed at (i) clarifying current roles and responsibilities with respect to underground storage, (ii) synthesizing scientific knowledge and risk assessment methodology, and (iii) setting reasonable goals for the management of CO_2 storage.

Local and global risks are currently regulated by different entities, within different regulatory frameworks, at different levels of government. In Canada, the regulation of local risks is a provincial responsibility performed by entities such as Alberta's Energy and Utilities Board (EUB).

The EUB already regulates the disposal of CO_2 and H_2S mixtures (Section 2.2.1). AGI is the best regulatory analogue for CO_2 storage, because the toxicity of H_2S means that the regulatory goal is to keep the gas from leaking to the surface. Like the injection of CO_2 for the purpose of avoiding atmospheric emissions—and unlike CO_2 injection for EOR—the regulation of AGI is aimed at ensuring safe, long-term disposal. Moreover, like CCS at coal-fired power plants, AGI links SO_2 and CO_2 emissions and thus provides a test bed for multipollutant regulation (Section 4.3.1).

Uncertainty in the effectiveness of CO_2 storage, arising from uncertainty in the lifetime of stored CO_2, is not currently addressed by any Canadian government entities. It will need to be. If Canada uses CO_2 storage to meet international commitments under the UN-FCCC, the federal government will need to account for it in the national emissions inventory. The responsibility for managing this process will presumably be divided among the departments of Foreign Affairs and International Trade, Environment, and Natural Resources.

The status of CO_2 storage under the UN-FCCC is unclear. While both the Kyoto Protocol and the recent Conferences of the Parties in Bonn and Marrakech explicitly endorse the use of CO_2 storage,[18] crucial questions regarding the incorporation of CO_2 storage within the framework convention's emissions accounting rules remain to be decided. The crux of the problem is deciding the extent to which CO_2 storage counts as non-emission.

The difficulty in building a system for regulating CO_2 storage is not simply due to the technical uncertainty in predicting the lifetime of CO_2 in reservoirs; it also arises from uncertainty about the goals of storage. Should the median lifetime of CO_2 in storage facilities, for example, be 500 years or 10 000? What fraction of early failures are we willing to accept? Uncertainty in predicting the fate of CO_2 in reservoirs cannot be eliminated. The regulatory system cannot therefore demand zero risk or perpetual storage. It must incorporate some "permission to fail." The challenge is to build a regulatory regime that works despite these uncertainties. Efforts to design technology for injection and monitoring of CO_2 and to craft a system to regulate these activities cannot succeed until there is some common understanding about these programmatic goals (Figure 4).

[18] In Article 2, Section 1, the Kyoto Protocol includes "Research on, and promotion, development and increased use of, new and renewable forms of energy, of carbon dioxide sequestration technologies," as a method for Parties to achieve their "quantified emission limitation." The agreement at the seventh Conference of the Parties in Marrakech requests that the Intergovernmental Panel on Climate Change (IPCC) study "geological carbon storage technologies" (Paragraph 7) and endorses CO_2 capture in Paragraphs 8.d, 13.d, and 29.

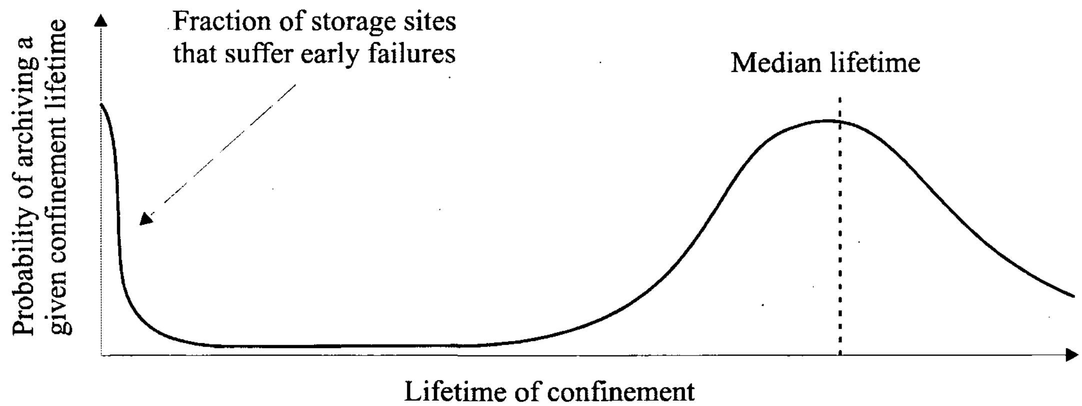

Figure 4. A schematic illustration of the probability distribution of confinement lifetime in a hypothetical set of storage reservoirs. The shape of the probability distribution will be determined by the technical standards for site selection, injection, and monitoring. These standards should themselves be chosen so that the resulting performance—expressed here as the probability distribution of confinement lifetimes—meets the overall programmatic goals. Two crucial programmatic goals are illustrated: the expected lifetime of CO_2 in storage reservoirs, and the fraction of storage sites that suffer early failure.

4. Implementing CO_2 Capture and Storage in Canada

4.1 A Strategy for the Oil and Gas Sector

Government action to encourage the adoption of CCS technologies in the O&G sector could yield significant, low-cost reductions in CO_2 emissions within the Kyoto commitment period while building the institutional and technological capacity necessary for broader use of CCS in the future. Specifically, I estimate that emissions could be reduced—compared with business as usual—by about 20 Mt-CO_2/year at an average cost of \$15–25/t-CO_2. As a sector in which to focus government action on CCS technologies, O&G offers several distinct advantages over electric power generation:

1. *Technical opportunity*. Because of the presence of large high-CO_2-concentration gas streams, the cost of CO_2 capture is less than half that in the electric sector. In addition, rapid growth in the O&G sector adds to its attractiveness, because CO_2 capture would be built into new facilities where costs are generally lower, rather than added to existing systems where costs will be higher and process optimization more difficult to achieve. If action is delayed, much of this opportunity for low-cost mitigation will be lost.

2. *Institutional ability*. Many of the large multinational firms in the O&G sector are uniquely able to manage the rapid implementation of CCS technologies. Specifically, these firms have in-house technical expertise covering all facets of CCS from CO_2 capture to long-distance transport and geological storage and an institutional culture that emphasizes long-range planning under uncertainty. In sharp contrast, many firms in the electric power generation sector are focused on near-term issues arising from market restructuring and lack the technical depth to effectively manage uncertain new technologies.

3. *Opportunity for constructive public engagement*. Wherever it is introduced, CO_2 storage is certain to generate public controversy. This controversy arises from specific concerns

about the safety of storage and more general concerns about sustainability. The introduction of CCS in the O&G sector will likely tend to focus debate on the safety and longevity of CO_2 storage rather than on the choice between fossil and non-fossil primary energy, as would the use of CCS in electric power generation. While both concerns are legitimate, debate centred on the former will be more likely to resolve key questions about the acceptability of CCS technologies. Moreover, both environmental non-governmental organizations (ENGOs) and the public are concerned about the environmental impacts of O&G production—both because of its rapid growth and because much of the production is exported—and use of CCS will directly reduce these impacts.

4. *Commercial benefits for Canadians.* Development of novel technologies for integrating CO_2 capture with natural gas processing and petroleum refining operations could produce an export-driven market for Canadian firms. Related claims can, of course, be made for almost any investment in CO_2 mitigation, but the claim is particularly plausible here because of the comparatively large size and technical sophistication of the Canadian O&G sector. While investment in wind or coal-CCS electricity generation could also generate commercially valuable Canadian expertise, the case is less plausible because of the weak Canadian position in the design and construction of wind turbines or coal-fired power plants.

4.1.1 Policy Options and Economic Instruments

A wide variety of policy instruments might be employed to drive adoption of CCS technologies in the O&G sector. Policy design will be unavoidably complicated by the divergence of federal and provincial interests, the limited suite of available policy instruments, and limited analytical capabilities of governments in a technically complex arena. Industry accepts that some GHG restrictions are inevitable, but argues that a cap-and-trade system would favour weak companies with slower growth rates; instead, industry is arguing for individually negotiated (company-by-company) caps on emissions intensity (e.g., kg-CO_2/bbl).[19] Individual caps are a blunt instrument, however, because they encourage companies to transfer emissions outside their operations without changing actual emission rates, thereby complicating emissions accounting and obscuring the real costs of emissions control. Plausible policy instruments include:

1. *A sector-wide price on CO_2 emissions.* A tax or cap-and-trade system could be applied to set an even price for GHG emissions throughout the upstream O&G sector. A tax naturally puts a constant price on emissions as production expands, but a cap-and-trade system could do the same if the total number of permits was increased in proportion to production. If needed, the ratio of permits to production could be made to decline according to an agreed schedule. This latter option allows transparent, economically efficient, sector-wide regulation of emissions intensity.

2. *Specific credits for CO_2 storage.* Specific monetary credit could be given for CO_2 stored in geological reservoirs, with a compensating increase in royalties or taxes to maintain overall sector-wide revenue neutrality.

3. *A sector-wide price on fugitive/non-combustion CO_2 emissions.* A tax or tradeable permit system could be imposed on non-combustion CO_2 streams.

[19] Personal communication, Rick Hyndman, Senior Policy Advisor on Climate Change, Canadian Association of Petroleum Producers, October 2001.

4. *Encouraging the adoption of enabling technology*. Rapid growth in long-lived capital stock in the O&G sector, in combination with the cost advantage of implementing CO_2 controls for new facilities rather than retrofits, means that there may be public value in driving the adoption of technology that would allow future implementation of CO_2 capture at low cost prior to imposing systematic CO_2 controls. For example, capital depreciation rates could be adjusted for specific hydrogen production technologies.

4.1.2 The Need for Improved Cost Analyses

New analysis is urgently needed to quantify near-term potential for implementing CCS in the O&G sector. Previous analyses have examined the overall costs of CCS across economic sectors, looking at both combustion and non-combustion sources of CO_2. Such analyses tend to focus on the largest CO_2 sources—electric power plants—where the costs of mitigation are high and the likelihood of early action is low. Further, because of their breadth, such analysis cannot include sufficient analytical detail to make a robust estimate of the costs of control for non-combustion sources.

What is required is an analytical effort focused on estimating the lowest-cost end of the supply curve for CO_2 mitigation using CCS. The rapid pace of change in O&G production strongly suggests that such an effort should not focus exclusively on estimating the costs under current market conditions, but must instead strive to incorporate forecasts of market growth. This is particularly true in assessing the cost of capturing NG-CO_2 and H_2-CO_2 (Section 2.2). The analysis should aim to quantify the uncertainty in cost estimates, explicitly documenting the dependence of cost estimates on assumptions about government and industry behaviour.

4.2 A Strategy for the Electric Sector

The use of fossil-fuel-based electric power generation with CCS could enable deep reductions in the CO_2 emissions from Canada's electric sector while maintaining growth in electricity supply. It is reasonable to aim at reductions of 50% by 2020 and to expect that the marginal increase in generation costs will be between \$15/MWh and \$25/MWh. In addition to the evident dependence on the performance of the CCS technologies themselves, the marginal mitigation cost is strongly dependent on three other factors—the price of natural gas, the stringency of control on conventional pollutants, and the cost of CO_2 storage (or value, if CO_2 is used to enhance upstream O&G production using EOR or enhanced coal bed methane).

It is technically possible to implement CCS electric power generation technologies quickly enough to achieve deep emissions reductions in the 2008–2012 Kyoto commitment period—as suggested in the AMG report—but a strategy aimed at this end would have two serious disadvantages:

1. The necessary rapidity of action would increase the cost of CO_2 mitigation by limiting opportunities for learning-by-doing and for leveraging global R&D efforts aimed at reducing CCS costs (Section 2.1.2). The costs would likely be higher and more uncertain than they would be under a strategy based on coal-to-gas fuel switching. Strong technology-specific incentives might then be required to force the implementation of CCS.

2. Rapid implementation of CO_2 storage would force rapid resolution of the regulatory questions described in Section 3.2, thus increasing the risk of setting bad regulatory

precedents. The rapidity would likely limit the opportunity to craft a broadly based risk assessment process and might limit public involvement in such a process. Such a process could easily result in strong public opposition. The use of CCS-specific incentives to encourage implementation, as described above, would increase the likely opposition by ENGOs, because it would directly pit CCS against coal-to-gas fuel switching, an alternative that would in this case be lower in cost and is already preferred by several ENGOs.

Near-term government action to encourage the development of CCS technologies in Canada could secure the option of using CCS to achieve deep reductions in CO_2 emissions from electric power generation. Any technology development program aimed at reducing future costs faces difficult choices in allocating resources between R&D and demonstration projects. In developing CCS in Canada, several strategic factors suggest a particular focus on demonstration projects. First, Canadian firms have comparatively little expertise in manufacturing the core component technologies, such as gas turbines or coal gasifiers, whereas Canadian firms have comparatively strong positions in the engineering and integration of large energy projects. Thus, the benefits of a demonstration project are more likely to be retained by Canadian firms than are benefits accruing from R&D on the component technologies. Second, early CCS demonstration projects will likely attract significant international R&D funding, and some of the expertise and intellectual property will be retained by the host country. An early Canadian demonstration of electric power generation with CCS would likely attract international collaboration, as has been demonstrated by the CO_2 storage monitoring program at PanCanadian's Weyburn EOR project.

4.3 Crosscutting Issues

4.3.1 Multipollutant Control

There are strong technological links between the control of CO_2 and the control of conventional air pollutants. These links are particularly important for coal-fired electricity generation but are also important in the O&G sector. Government policy must account for these links if it is to achieve cost-effective regulation of CO_2 and conventional air pollutants.

The marginal cost of capturing CO_2 from coal-fired power plants is strongly dependent on the stringency of controls on conventional pollutants (SO_x, NO_x, particulate matter, toxic metals). The reasons are simple: most proposed CO_2 capture plants have very low emissions of conventional pollutants, so their cost of electricity is roughly independent of the stringency of pollution control; for plants without CO_2 controls, however, the cost of electricity rises significantly with the stringency of control. Moreover, controls on conventional pollutants generally decrease plant efficiencies—increasing CO_2 emissions per unit of electricity and so further increasing the cost of CO_2 control with increasing stringency of control on conventional pollutants (see Figure 2). CO_2 capture plants will differ in their control of air pollutant emissions, and some designs may increase emissions; post-combustion capture with amines, for example, can increase NO_x emissions per unit of electricity because amine capture decreases plant efficiency without removing NO_x [16].

If the regulation of conventional air pollutants were static, then it might be reasonable to ignore the coupling between CO_2 and air pollution. The regulatory environment, however, is changing rapidly, driven by new scientific understanding of the health and environmental impacts of pollutants and by continued improvement in the technical and economic performance of emission control technologies. Important areas in which new scientific understanding may influence the regulatory environment include (i) the health effects of fine particulate matter; (ii) the formation of secondary particulates from gaseous emissions of SO_x and NO_x; (iii) the effect of industrial NO_x emissions in generating ozone far from the sources of emission; (iv) the environmental and health impacts of low levels of ozone; and, finally, (v) the hazards posed by emissions of metals such as mercury. The proposed Canada-wide Standards for ozone and $PM_{2.5}$ reflect this emerging knowledge of the risks of air contaminants, but it is highly unlikely that the standards represent the final word on this issue. More plausibly, change in the regulatory environment for air contaminants will continue and will be at least as rapid as changes in the regulation of CO_2 emissions.

The technological link between control of CO_2 and control of air contaminants demands a corresponding link between government policy in the two domains. Without such linkage, the environmental regulation of power plant emissions is unlikely to be cost effective. Consider the management of emissions at coal-fired power plants. Without linkage, air pollution regulations might force operators to install expensive control technology in the next decade, only to have the plants retired a few years later because of restrictions on CO_2 emissions. In contrast, a coordinated policy might achieve the same environmental benefit at lower cost by accelerating the implementation of near-zero emission technologies, while allowing some existing facilities to run without new control technology until their retirement.

The multipollutant control problem is particularly difficult in Canada because of the absence of effective programs for emissions trading. If control of CO_2 and control of SO_2, for example, were both achieved through measures that set a price on emissions, then efficient multipollutant control might emerge without explicit government action. In the existing policy environment, however, where governmental measures are predominately sector specific and standards based, it is likely that opportunities to efficiently mitigate both pollutants will be missed.

Near-term options for building multipollutant considerations into CO_2 control policy include the following:

1. Focus CO_2 control efforts on technologies or sectors where multipollutant benefits are largest—coal rather than gas, for example, or heavy freight transport rather than personal automobiles.

2. Explicitly mandate the consideration of air pollutants in allocating resources for CCS R&D and demonstration projects. For example, if all other factors are equal, then gasification or oxygen-fired retrofits should be given precedence over amine capture.

3. Build multipollutant control into targeted programs for CO_2 control that will result in new long-lived capital stock by setting program-specific emissions prices for key pollutants. A reverse auction for emissions reductions similar to that of Pilot Emissions Reductions, Removals and Learnings, a pilot initiative of Environment Canada, might build in explicit prices for SO_2 and NO_x that would be used solely to compare bids in the auction program without committing the government to broad-based emissions prices.

4.3.2 Induced Technological Change

Distributing the burden of emissions mitigation across economic sectors, across geographic regions, and between present and future is one of the thorniest problems in climate policy. Two distribution problems are particularly relevant to the implementation of CCS. The first is the distribution of burdens between economic sectors; however, because this topic was carefully addressed in the AMG report, little additional discussion is needed here. The second is the distribution of effort between the Kyoto and post-Kyoto periods: current resources may be directed either to reducing emissions in the 2008–2012 Kyoto commitment period or towards achieving efficient mitigation over a longer period.

The Kyoto versus post-Kyoto distribution is often framed as a choice between spending aimed at achieving immediate mitigation of emissions and spending on R&D that can drive down the cost of mitigation in the future. This framing is too restrictive, however, because spending aimed at achieving immediate emissions mitigation can also reduce the cost of future mitigation without government-sponsored R&D. Government action that sets a price on CO_2 emissions in a given sector induces private innovation that can bring down the cost of mitigation. Such induced (or endogenous) technological change can occur in many ways, ranging from the acceleration of learning-by-doing in the application of existing technologies to the creation of new technologies by induced R&D in the private sector. Because of the long time horizon of the climate problem, induced technological change plays a crucial role in determining the cost of emissions control [17–19].

The presence of induced technological change has important implications for climate policy. Most generally, there is an unavoidable coupling between the allocation of burdens in the Kyoto and post-Kyoto periods. More specifically, while an economy-wide tradeable permit system that equalizes the marginal price of emissions mitigation across the economy may produce the most economically efficient mitigation in the short run, it may be inefficient in the long run. This would, for example, be true if the resulting carbon price were too low to induce innovation in a sector where early innovation was important for bringing down the long-run cost of mitigation. The upshot is that the problems of sectoral and temporal allocation described in the first paragraph of this section are tightly entangled.

Considering the implementation of CCS, the distribution of financial burdens between the O&G sector as described in Section 4.1 and the electric sector as described in Section 4.1.2 is also a choice between the mitigation of emissions in the Kyoto and post-Kyoto periods. It will be difficult for government decision-makers to craft a robust consensus about the allocation of funding for CCS absent some programmatic guidance about the appropriate distribution of current federal resources for CO_2 mitigation between the disparate Kyoto and post-Kyoto goals. These issues cannot be resolved by departmental program managers; clear guidance from higher levels of government will be required to resolve this allocation problem.

4.3.3 The Federal Role in Regulating and Managing CO_2 Storage

It seems plausible that existing systems for regulating the underground disposal of wastes from the O&G sector—an area of provincial jurisdiction—could be extended to successfully manage the *local* risks arising from large-scale geological storage of CO_2. While Environment Canada may have little to no direct responsibility for managing the local risks, there is reason to contemplate a federal role in facilitating risk assessment and risk communication and in documenting CO_2 storage activities.[20] This role might reasonably be split between Natural Resources Canada and Environment Canada.

[20] Such documentation might include the quantity injected, the methods used for injection and monitoring, and a summary analysis of significant problems or failures.

If CCS plays a significant role in managing Canada's CO_2 emissions, then there may be a gigatonne of CO_2 stored in underground reservoirs in Canada within several decades. It seems very likely that a new federal regulatory system will be needed to successfully manage the global risks of large-scale CO_2 storage—the possibility of leakage that could compromise the effectiveness of CO_2 storage in mitigating atmospheric emissions. Although management of geological resources, and of the local effects of CO_2 storage, is a provincial responsibility, the management of CO_2 stored to avoid atmospheric emissions implies a federal responsibility, because it arises from national and international commitments to control CO_2 emissions. The discharge of this federal responsibility would fall, at least partially, under the jurisdiction of Environment Canada.

Considering the more immediate future, one might argue that Environment Canada could avoid involvement in the regulation of CO_2 storage until a problem arises. The storage of CO_2, after all, will start small. Moreover, provincial regulators already manage the storage of CO_2 when it occurs as a side effect of AGI (Sections 2.2.1 and 3.2), and there seems little immediate likelihood of any serious challenge to the idea that CO_2 stored in geological formations should be excluded from national emissions inventories.

While delay is possible, there are strong arguments for early federal involvement in the regulation of CO_2 storage. Within this decade, Canadian firms will likely seek permits to inject significant quantities of CO_2 underground for the explicit purpose of avoiding CO_2 emissions to the atmosphere. Without adequate assessment of the risks of CCS and of the existing regulatory environment for CO_2 storage, there is a risk that environmental regulators will respond ad hoc, crafting regulations to fit the demands of the moment without adequately understanding their long-term implications. Such early regulatory action is often difficult to amend and could affect the development of the technology for decades. Efforts to build a robust regulatory environment for geological storage cannot wait until the technology is ready for large-scale application. Environmental regulators, industry, and ENGOs need to begin to build a common understanding of the current state and future course of regulation, identifying areas of common concern and developing compromises to address areas of disagreement. Environment Canada should lead this effort.

Specific areas in which early action by Environment Canada appears most likely to be useful include the following:

1. *Risk assessment*. Environment Canada should facilitate an assessment of the risks of CO_2 storage. The effort should be coordinated with efforts under way in the United States and elsewhere. While the explicit purpose of the assessment will obviously be to improve technical understanding of the risks, a well-run assessment process that involves diverse stakeholders can serve a vital role in building public trust, even if little new knowledge is generated.

2. *Setting goals for CO_2 management*. Research aimed at improving the tools for monitoring storage is already under way in Canada. Improved technical understanding is, however, a necessary but insufficient requirement for the successful management of CO_2 storage. The risks of CO_2 storage cannot be eliminated, and a management regime that aims at zero risk will be certain to fail. Stakeholders need to clarify the strategic goals at which a management regime should aim. Environment Canada should facilitate an inclusive process aimed at defining such goals (Section 3.2, Figure 4).

3. *Clarifying international commitments*. As discussed in Section 3.2, the status of CO_2 storage in the international climate policy regime has not been completely resolved. In concert with the Department of Foreign Affairs and International Trade, Environment Canada should seek resolution.

5. Summary: Specific Roles for Environment Canada

If CCS is widely implemented, Environment Canada will play multiple, partially independent roles in managing the technology. Many roles for Environment Canada are implicit in the foregoing discussion of strategies for implementation. In some areas, such as the near-term use of CCS in the O&G sector (Section 4.1), managerial responsibility is spread between multiple federal and provincial departments in a complex and already somewhat contentious mixture. Sorting out the precise roles for Environment Canada is beyond the scope of this report. In other areas, such as multipollutant regulation (Section 4.3.1), the role for Environment Canada emerges more clearly due to the overlap between the department's responsibilities for conventional air pollution and its responsibilities for GHGs. Finally, in Section 4.3.3, I argue that there is a specific role for Environment Canada in managing long-term CO_2 storage.

Environment Canada has a broader role in promoting the success of a national regime for managing CO_2 emissions, a role that is distinct from the details of building an effective and efficient system for managing CO_2 capture and storage. Over the next half century, the cost of managing CO_2 emissions will likely rise steadily to a total of over 1% of Canada's GDP. The urgency of disputes over the management of CO_2 emissions will likely continue to grow with the size of the economic stakes. With respect to CCS, there will likely be two crucial areas in which it will be vital to build public trust. The first is in ensuring the safety and stability of CO_2 storage. The second, and perhaps most important, is in the distribution of resources between CCS and other means of managing CO_2 emissions. In both areas, Environment Canada has a responsibility to ensure that environmental concerns are given—and are publicly seen to be given—serious consideration.

6. References

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