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ERCB decision on an acid gas disposal scheme: further lessons for the regulation of carbon capture and storage schemes

By Nigel Bankes and Trevor Ference

Cases Considered:

Re: AltaGas Ltd, Applications for Two Pipeline Licences, An Amendment to a Facility Licence, and Approval for an Acid Gas Disposition Scheme, Pouce Coupe Field, ERCB Decision 2009-073

During the fall of 2009 the province of Alberta signed letters of intent for funding with four proponents for carbon capture and storage schemes (CCS): (1) Swan Hills Synfuel for an in situ goal gasification and enhanced oil recovery (EOR) project, (2) Enhance Energy and Northwest Upgrading for a CO_2 trunkline, (3) Shell for the Quest project and (4) TransAlta for Project Pioneer. As these proponents move to implement their projects we will start to see how the existing and proposed regulatory scheme accommodates CCS projects. There are perhaps four types of legal and regulatory issues that project proponents face in relation to the storage elements of any project: (1) property issues (e.g. pore space ownership); (2) regulatory issues (Energy Resources Conservation Board (ERCB) approvals); (3) liability issues (will long term liability for storage sites transfer to the province?), and (4) crediting issues (how will CCS projects be treated within the context of Alberta's *Specified Gas Emitters Regulation,* Alta. Reg. 139/2007; will CCS projects create emission performance credits or offset credits?). The Carbon Capture and Storage Development Council (*Accelerating Carbon Capture and Storage Implementation in Alberta*, Final Report, March 2009) has urged the province to provide guidance and regulatory certainty on these issues but, by and large, the province has yet to act.

This recent ERCB decision is principally of interest in relation to the second category of issues noted above (i.e. regulatory approval). It is significant in the context of CCS because the ERCB currently takes the view that it will treat CCS projects as acid gas disposal (AGD) projects for the purposes of regulatory review and approval: see, principally s.39(1)(d) of the *Oil and Gas Conservation Act*, R.S.A. 2000, c. O-6, (*OGCA*) and ERCB Directive 65 on Resources Applications. And although there are a few other ERCB decisions dealing with AGD projects (see Bankes and Poschwatta, *Carbon Capture and Storage in Alberta: Learning from the Acid Gas Disposal Analogy*, Resources # 97 (2007)) most of these earlier decisions deal with the possibility of flaring if injection is shut down, rather than the larger subject of the downhole containment of the acid gas plume. This decision however does focus on this latter issue as part of the discussion of the injection well aspects of the proposal.

The applications

As noted in the title to the Board's decision, there were four related applications before the Board. The first was an application to add capacity to an existing sweet gas processing plant to allow it to handle a sour gas stream (maximum H_2S content 5%). The second was an application to construct a 2.58 km acid gas pipeline from the plant to the injection site with a maximum H_2S content of 80%. The third was an application to construct a 12.7 km sour gas pipeline from the field to the plant (maximum H_2S content 5%). And the fourth was an application to dispose of gas into the Belloy formation, a saline aquifer formation, through an existing well. This comment focuses on this last application although it begins with some discussion of the first application.

The Board's consideration of the applications

The proliferation issue

The principal issue that led to a Board hearing rather than the administrative approval of the application was the issue of facility proliferation. Indeed, this issue led to a dissenting opinion from acting Board member Jeff Gilmour. Intervenors argued that AltaGas had simply not done a good enough job of proving the case that it had to meet: i.e. that it had explored other opportunities for processing an acid gas stream within the immediate vicinity of the plant. This is not a new issue for the Board and it is closely tied to the general issue of cumulative impacts of oil and gas operations, but in reading the decision (both the majority decision and the dissent), one is struck by the question of whether the correct (and enough) parties are before the Board to deal with this issue. For example, the applicant before the Board in this case is AltaGas as the plant operator. There were six existing plants within 5 and 28 kms of AltaGas Plant but attention focused on an existing sour gas plant operated by Spectra as well as another new plant under construction and to be operated by Birchcliff. Both Spectra and AltaGas are midstream operators. Neither Spectra nor producers in the area (including Birchcliff) were before the Board on this application; and while there was evidence before the Board of some correspondence between AltaGas and Spectra, it would be hard to characterize this as evidence of serious negotiations about reasonable commercial alternatives. In fact, it seems best characterized as the absolute minimum dance (you scratch my back, I scratch yours) between two mid-stream competitors that might satisfy the Board in this and similar future applications involving the same or other competitors. Mr. Gilmour was not convinced that this was adequate (at 26) but the majority was persuaded (at 9) that AltaGas "substantially met the proliferation requirements of the Board."

Are there lessons from this part of the application for CCS projects? We think that there may be. First, there is an ongoing discussion in this and other decisions as to the legal implications of Board Directives. The recent Court of Appeal decision in *Kelly et al v. ERCB and Grizzly Resources Ltd.*, 2009 ABCA 349 (and for comment on this decision and the Board's response see Shaun Fluker's ABlawg post) showed the Board's vulnerability on this issue, but the present decision suggests that there are continuing challenges facing the Board. The issue is not simply one of handing down decisions that will withstand judicial scrutiny, the issue is also one of convincing the public that the Board is regulating in the public interest, in a rigorous way, and according to some objective standards. If the Board takes the position that it can regulate large scale, long-term CCS projects by way of Directives and the terms and conditions of scheme approvals to supplement a single sentence in the *OGCA* (s.39(1)(d)), then the public, and indeed applicants, need to know the extent to which Directives are mandatory and the basis on which the Board will waive apparently mandatory requirements. This decision does little to clarify these questions (see especially the majority's discussion (at 9) indicating that if the applicant had not met requirements that turned out to be mandatory then the Board had the discretion to waive such requirements).

Second, there is the question of whether the Board's approach to proliferation is adequate in this and other contexts. The Board very much operates (like the provincial government) on the philosophy that there is no need to provide for economic regulation of the upstream sector of the industry unless absolutely necessary. Thus the Board sanctions competitive drainage (and the drilling associated with such operations), common orders and rateable take orders are notoriously difficult to obtain (see, for example, BP Energy Company, Rateable Take, Blackstone Beaverhill Lake A Pool, AEUB Decisions 2003-016), the province will not proclaim compulsory unitization legislation, and both the province and the Board find it very difficult to deal with cumulative impacts (see Steve Kennett's many writings on these issues in *Resources* and elsewhere – see most recently *Resources # 104* (2009)). The question on a go-forward basis is whether this is the approach we want to take to the development of CCS projects, with individual proponents coming forward with a variety of different projects with little effort to coordinate both the selection of preferred storage sites and CO_2 pipelines. This is partly an issue for the Board to grapple with, but it is also an issue for the province in terms of the rules that it adopts for the disposal of Crown owned subsurface disposal rights.

The proposed injection scheme

By contrast with the proliferation issue, the Board's discussion of the injection scheme is quite short, covering some 7 pages in the report. The issues discussed included: location of the disposal well, acid gas containment in the disposal zone, applied for operating parameters and the proposed monitoring program.

The location of the disposal well (and this was a well originally drilled for other purposes that was to be converted to a disposal well) was principally an issue because it was located some distance (2.6 kms) from the plant site necessitating a high pressure pipeline from the plant with a high H_2S content (80%). Not surprisingly, intervenors would have preferred an injection site at, or closer to, the plant. The Board accepted AltaGas' proposal noting that it had four main concerns (at 27):

- adequate injectivity, so that the maximum disposal rate could be achieved;
- storage capacity large enough so that the cumulative acid gas volume could be injected without pressuring up the reservoir;
- isolation of injected acid gas to the disposal zone; and
- no impact on producible hydrocarbon reserves.

Available sites at the plant location did not satisfy some or all of these requirements.

Geological containment is clearly crucial to the safety of any AGD project. In this case the Board could take some comfort from the fact that there were already five AGD projects in operation that were making use of the Belloy formation, none of which (at 29) had disclosed problems with the acid gas reacting with formation water or the formation itself. Thus, the principal concerns related to offsetting wells. The evidence showed that there were a number of wells that penetrated the Belloy formation within the vicinity of the injection well (a map filed with the application shows 8 such wells within immediately offsetting sections) and in particular, attention focused on two producing wells from offsetting sections immediately to the east (the injection well was proposed for section 10, the wells were producing from sections 11 and 12) and producing from a deeper formation (and both operated by Signalta). The other wells had been abandoned and cemented.

The Board accepted that the applicant had been able to demonstrate containment. The caprock seal was provided by the impermeable Montney Formation 250 metres thick and there was no evidence that previous earthquakes in the area had caused damage to existing facilities. The Board did require AltaGas (at 29) to determine the integrity of the casing cement of the two Signalta wells before injection commences. In doing so, the Board went beyond what AltaGas had proposed (at 28) which was to check the cement bond for just one of the wells on the basis that both wells had been completed at about the same time and could be expected to have similar cement jobs. The Board did not require AltaGas to conduct tests in relation to wells that been abandoned with cement plugs within the area of possible acid gas migration. The Board concluded (at 30) that the "cement plugs within the wellbore will be adequate to prevent acid gas from migrating uphole to either groundwater or the surface." The plugs preventing uphole flow had cement thicknesses above the Belloy formation of between 9m and 130m. The Board decision does not discuss the dates when these wells might have been drilled and abandoned or the nature and quality of the cement that might have been used.

For operating parameters the Board approved a maximum wellhead injection pressure of 10 megapascals (mPa) which was based on the maximum approved operating pressure of the proposed pipeline rather than the 18 mPa sought by the applicant. The Board took the view that if AltaGas encountered injectivity issues it could apply for an increase in injection pressure. While AltaGas expected to operate with about 70% H_2S and 30% CO_2, the Board fixed the maximum H_2S content of the injection stream at 80% in order to provide AltaGas some operational flexibility. Emergency response plans would be based on the 80% H_2S content. The Board also approved a total cumulative volume of gas to be injected over the proposed 15 year life of the project and a maximum reservoir pressure of 25 mPa pressure. This was in excess of AltaGas's estimate of the initial reservoir pressure at 21.35 mPa.

As for monitoring, the Board accepted AltaGas's proposals to monitor the surface casing of the two Signalta wells every three months for H_2S content and monitor production from these wells at the gas plant on a continuous basis in order to check for H_2S content. The Board also accepted AltaGas's proposal to monitor production annually from one other offsetting well which was producing from a formation above the Belloy. The Board did not require surface monitoring for any of the offset abandoned wells with cement plugs.

Once again it is worth concluding this section by asking about the lessons for CCS since it seems likely that principal criteria that the Board uses to examine AGD projects will also apply to CCS projects: injectivity, capacity, containment and resource sterilization. In relation to the latter it is interesting to note that AltaGas was able to obtain approval for its injection project even though it was operating in close proximity (adjacent sections) with producing wells from a deeper formation.

It is also useful to compare the Board's treatment of this application with proposals in the United States for the licensing of CO_2 injection wells under the terms of the Underground Injection Control (UIC) Program of the Environmental Protection Agency (EPA) pursuant to the federal *Safe Drinking Water Act*. This is not the place to provide a detailed comparison between ERCB practice and the EPA proposed rules for a new class of wells, Class VI wells, but here are three points.

First, the EPA proposal will require the applicant for a permit to identify an area of review (AoR) and a corrective action plan. The AoR is used, in conjunction with data collected on the properties of the injection and containment zones, to assess the geological suitability of a proposed site.

The AoR is to be established by predicting the migration of the CO_2 plume over the lifecycle of the project and is derived using multi-phase computational fluid flow modeling (EPA at 43506). Traditionally, the EPA's well classification framework under the UIC program establishes the AoR at a fixed radius, of either ¼ or 2 miles. However, in recognition of the unique challenges associated with geologic storage of CO_2, the proposal will require the applicant to establish an AoR for CO_2 sequestration projections using simulation. The use of modeling to establish the AoR is justified given that the volumes of CO_2 will likely be orders of magnitude greater than those currently observed in AGD operations. For such injection sites the effects of the plume and the pressure front have the potential to extend hundreds of kilometers from the injection site, potentially intersecting hundreds and even thousands of active and abandoned wells. (see Celia et. al., "Risk of Leakage versus Depth of Injection in Geological Storage" (2009) 1 Energy Procedia 2573-2580 for a more detailed discussion).

Another primary purpose of the AoR is to define the applicable zone for the corrective action plan. In a corrective action plan, the owners or operators of disposal wells must demonstrate that all artificial penetrations within the applicable zone will not contribute to the migration of CO_2 outside the containment zone. In doing so they are required to compile and tabulate data for all artificial penetrations, active or abandoned, and to assess whether they have been properly plugged. They are also required to perform corrective actions, regardless of ownership, where deficiencies are identified that may serve as a conduit for migration to the surface or into underground sources of drinking water (USDW) (EPA at 43507). Since the EPA proposal recognizes that the applicable zone may intersect a large number of wells, there is some discretion to allow owners and operators to complete corrective actions in phases.

Second, during the operation of the well, owners or operators are required to periodically reevaluate the AoR and the corrective action plan. Data collected through the required monitoring activities (which include monitoring the subsurface extent of the CO_2 plume and pressure front) is to be used to confirm the accuracy of AoR modeling. Where viable, such monitoring should be conducted using pressure gauges installed in the first formation overlaying the containment zone. However, in the event that this alternative is not viable or available, the EPA has specified a number of less intrusive methods which can be used to monitor the subsurface migration of CO_2. Where the results of such monitoring deviate from the initial AoR and corrective action plan and intersect additional artificial penetrations, owners and operators of the injection well are responsible for completing corrective actions (EPA at 43508). In addition, as part of a permit application, owners and operators must provide a description of how the public is to be informed in the event operational results necessitate amendments to the AoR.

Third, as part of the application process the applicant must submit a well plugging plan and a site closure plan for approval (EPA at 42518). In this plan, owners or operators are required to specify the type and number of plugs, the placement and elevation of each plug and the method to be used to place the plug. In addition, owners or operators are required to provide a plan for integrity testing to ensure the integrity of the well prior to site closure. Sixty days prior to ending injection activities, or in the event that the plan no longer reflects what is likely to occur, an amended plan is to be submitted for approval.

There are many similarities between the approaches currently used by the EPA and the ERCB to regulate AGD. In their proposal the EPA creates an independent class of well for the regulation of large scale long term storage of CO_2. In creating a new class the EPA draws on the experience of AGD operations while addressing the risks associated with long term storage. The EPA proposal recognizes the unique challenges associated with subsurface storage of CO_2 and addresses the concerns surrounding the significant increases in injection volumes and the buoyant and corrosive nature of CO_2. Some of the key differences between the ERCB's current regulation of AGD projects and the EPA proposals include the following: (1) AoR based on modeling for each project, (2) the requirement for a corrective action plan to the extent that the injection does not perform as modeled, (3) assumption of responsibility for abandoned wells in the project area (under the *OGCA* the original licensee retains responsibility), (4) preparation of site closure plan at the outset.

A proposal for the Board

We have one concrete suggestion for the Board and it is this. The Board now has considerable experience dealing with AGD schemes. Both the Board and industry have learned from those schemes. For example, Alta Gas justified its surface vent monitoring of the Signalta wells on the basis of past experience noting that (at 32) "It is expected that if breakthrough occurred, CO_2 would show up before H2S, <u>as this had been with the experience with other schemes</u>" (emphasis added).

Our suggestion is that the Board should devote the time and resources to publishing a report precisely on: "the regulation of acid gas disposal projects: the experience and lessons learned for carbon capture and storage projects". We are aware that there are published studies of elements of this experience originating from both Alberta and British Columbia and authored by eminent authorities such Stefan Bachu (see for example Bachu and Watson, "Review of failures for wells used for CO2 and acid gas injection in Alberta, Canada" (2009) 1 Energy Procedia 3531- 3537, reviewing experience with injection wells (not other producing or abandoned wells which have been drilled through the storage formation) and comparing the performance of wells drilled for injection purposes and wells that are converted exploration / production wells). This is not the place to review all of those studies; the point here is simply that the Board itself has not published such a study indicating what it has learned as a regulator from this experience. We think that the publication of such a study (especially if subject to peer review) would go a long way to convincing the public that the Board is ready to undertake the responsibilities associated with regulating large scale CCS projects. The Board clearly has the authority to engage in such a reflective exercise of its own motion, or, alternatively, the Minister of Energy might request such a study and provide the additional resources that the Board might need to complete such a study.

Another analogy: natural gas storage

Acid gas disposal schemes offer one analogy for CCS schemes. Another analogy frequently referred to is natural gas storage. In a shameless plug, we note that Bankes and Gaunce have recently posted a series of pieces dealing with natural gas storage on the ISEEE website.

A note on the web-based availability of Board filings

Those interested in seeing what an AGD application looks like and who are not familiar with ERCB information transparency practices should know that all material filed in support of an ERCB resources application is available on the Board's website. But hurry! The material is posted there for only 30 days after the application approval (December 22, 2009) and then removed. To take a look, go to the ERCB home page then follow: (1) industry zone, (2) applications, (3) IAR query system, and (4) plug in the application number: 1567595.