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Continuing Liability for Well Abandonment

by Jerrad Kubik and Students-at-Law, Kerry McGinnis and Ashley Weldon

Introduction

A recent decision¹ of the Energy Resources Conservation Board (“the ERCB”) helps define the broad scope of well abandonment obligations while at the same time highlighting the challenges when ownership changes hands.

Facts

Southern Alberta Oil Company (“SAOC”) drilled a well in the Turner Valley, which produced crude oil from January 1919 to January 1922, after which production was suspended. In 1926, the well was zonal abandoned. In that same year, Dalhousie Oil Company Limited (“Dalhousie”) purchased most of SAOC’s assets, including the abandoned well. In 1958, the Turner Valley well was surface abandoned.

In 2005, a complaint regarding leakage from the well led Dalhousie to send the complainant land owner a cheque to cover the costs of fencing off the well. In conjunction with the complaint, the ERCB sent several letters to Dalhousie requesting that Dalhousie properly

abandon the well. Given Dalhousie’s inaction, the ERCB abandoned the well in 2006. In March 2008, the ERCB’s Corporate Compliance Group (the “CCG”) sent Dalhousie an invoice for the abandonment and warned the company that failure to pay in a timely manner would lead to a 25% penalty on top of the clean-up costs. Following Dalhousie’s failure to pay, the CCG issued Abandonment Cost Order (“ACO”) 2008-1, ordering Dalhousie to pay almost \$500,000 (which included the 25% penalty).

Issues

Dalhousie requested a hearing to contest ACO 2008-1, denying liability for the abandonment costs on three main grounds. First, Dalhousie denied its status as a working interest participant (“WIP”), asserting that the well was unitized in Order TVU No. 7 (the “Order”). Secondly, Dalhousie claimed that it sold the well to Signalta Resources Limited (“Signalta”) in January 2006. Third, Dalhousie raised issues of procedural fairness regarding the abandonment process.

ERCB Decision

The ERCB began its review by setting out the statutory framework under the *Oil and Gas Conservation Act*², (the “OGCA”). First, s. 30 of the OGCA states that the abandonment costs of a well must be paid by the WIP, and that a failure to pay the abandonment cost will lead to a penalty equal to 25% of the cost of abandonment. Secondly, s. 29 of the OGCA states that prior abandonment of a well does not insulate the WIP from future abandonment responsibilities.

The ERCB dismissed Dalhousie’s first argument, finding that the well did not fall within the scope of the unitization Order. In particular, the Order only applied to the Rundle Group and the well in question produced at least 650 meters above the Rundle Group. Dalhousie’s claim that it had sold the well to Signalta was also dismissed. The ERCB found that while Signalta had purchased Dalhousie’s interest in TVU No. 7, since the well in question was not part of TVU No. 7, it could not have been included in the sale to Signalta. Finally, Dalhousie’s claim

The regulatory requirements and liability for the suspension and abandonment of oil and gas wells are contained in sections 29 and 30 of the OGCA — these sections set out who the ERCB contacts to carry out the actual abandonment and who covers the costs of doing so, at least up front.

that the ERCB's abandonment process was procedurally unfair was dismissed because the time to raise this type of argument had long passed. Dalhousie should have raised issues of procedural unfairness with the ERCB at the time the company received directions from the ERCB to abandon the well.

Ultimately, the ERCB determined that Dalhousie was a 100% WIP in the well and was obligated under the *OGCA* to cover the costs of the abandonment and to pay the 25% penalty for failing to pay the costs in a timely manner. The ERCB also reminded Dalhousie that the company remained responsible for any future abandonment costs associated with the Turner Valley well, including reclamation costs.

Continuing Liability

The regulatory requirements and liability for the suspension and abandonment of oil and gas wells are contained in sections 29 and 30 of the *OGCA*—these sections set out who the ERCB contacts to carry out the actual abandonment and who covers the costs of doing so, at least up front. Section 29 also makes it clear that a well licensee and any WIPs remain responsible for the liability for any re-abandonment operations that may need to take place in the future. This ERCB decision confirms the broad scope of section 29 and highlights the fact that this section prevents a licensee, approval holder or WIP from “using previous abandonment of a well as a shield to protect them from liability for future abandonment work or abandonment costs... merely because the well had previously been abandoned to a satisfactory condition.”³

Sections 29 and 30 of the *OGCA* refer to regulatory liability. This liability, however, does not extend into the contractual context—who actually owns the well, and who agreed to be liable for past, present and future environmental liabilities. Contractual liability therefore refers to who has contracted to take on this risk. Often a well, and all the environmental liabilities flowing from the well (including abandonment costs), are transferred to the purchaser in a purchase and sale agreement using an environmental indemnity provision. As this ERCB decision demonstrates, a vendor seeking to dispose of its entire interest in a set of assets should ensure that the assets are carefully and specifically identified within the purchase and sale agreement from the outset. Once the purchase and sale has been completed,

both the vendor and the purchaser should also confirm that the transfers have also occurred at the ERCB, as well as with any other regulators that may be involved.

If this transfer does not occur, there may be a potential disconnect between the party with the regulatory liability and the party with the contractual liability. This is because the *OGCA* is clear that the abandonment of an oil and gas well or facility does not relieve a party from the liability and responsibility to conduct further abandonment operations in the future. The responsibility for this continuing regulatory liability is that of the current licensee or WIP named in the ERCB's records; the ERCB is not concerned, at least initially, with who is the actual owner or purchaser of the well.

This disconnect is further accentuated by Directive 006, which prevents a well license from being transferred for abandoned wells that have already been issued a reclamation certificate, among other categories of abandoned wells. Therefore, even if a well—and the environmental liability for that well—is transferred to a purchaser, the ERCB will not change the name of the current licensee if that well has received a reclamation certificate. In this situation, should the reclamation-certified well require future abandonment/reclamation efforts, the current licensee or the WIPs in the ERCB's records (i.e. the past owner) will be contacted to do the actual abandonment/reclamation work. That party will subsequently have to track down the party who is contractually responsible for those costs (i.e. the purchaser, or subsequent purchaser of the well) and may have to bring an action to recover the costs.

Concluding Thoughts

While this ERCB decision clearly defines the broad scope of well abandonment obligations under the *OGCA* and demonstrates how these obligations can stretch far into the future, this decision also brings to the surface the challenges and complexities involved in managing these regulatory and contractual liabilities.

Footnotes

¹ ERCB Decision 2010-19

² R.S.A. 2000, c.O-6

³ *Ibid.*, Note 1, p.4

ERCB Licence Transfers: a practice point

By Peter Doelman, Student-at-Law



What can happen when parties transfer licensed wells and facilities on a sale without first considering the Liability Management Rating (“LMR”) post-transfer?

ERCB-administered liability management programs

The Energy Resources Conservation Board (“ERCB”) administers several liability management programs (e.g. the *Licensee Liability Rating Program*¹, which governs most conventional upstream oil and gas wells, facilities, and pipelines). These programs are in place to prevent the Alberta public from bearing the costs to suspend, abandon or reclaim a well, facility or pipeline.

Liability Management Rating

Every month, each licensee has an LMR assessment that compares the licensee’s deemed assets and deemed liabilities under the applicable liability management programs.

$$\text{LMR} = \frac{\text{deemed assets}}{\text{deemed liabilities}}$$

The LMR is designed to assess a licensee’s ability to address its suspension, abandonment, remediation and reclamation liabilities. If a licensee’s LMR < 1.0 (i.e. deemed liabilities outweigh deemed assets), the licensee will be required to provide the ERCB with a security deposit.

In the context of a sale transaction, on receipt of a Licence Transfer Application (“LTA”), the ERCB will perform an LMR assessment on both transferor and transferee as if the transfer was approved. If following the assessment, either transferor or transferee would have a post-transfer LMR of less than 1.0, the ERCB will require a security deposit from the party whose LMR < 1.0 within 30 days of the date of the purported transfer.

What if a Party Doesn’t Pay?

If no deposit is received within the thirty (30) day period, the ERCB will cancel the transfer application and the licence will remain with the transferor.

This is a problem.

If the sale is closed, the transferor (licensee) no longer beneficially owns the assets (the assets have been conveyed), so it cannot establish that it retains surface and mineral rights or that it holds the required working interest participation pursuant to section 16 of the *Oil and Gas Conservation Act*. The transferor will be left with a well licence which it is not entitled to hold.

The consequences of this result include noncompliance fees and the potential of acquiring a “REFER” status and a spot on the dreaded Enforcement Ladder. A REFER status means pending and future ERCB applications are considered “nonroutine”, which take longer to process.²

What Can You Do?

Do your homework

Parties can pre-calculate the post-transfer LMR values of the transferor and transferee as part of their due diligence to determine if a deposit will be required, and if so, can plan accordingly.

Drafting

Parties can also include a covenant in their sale agreement providing for payment to the ERCB in the event there is a post-transfer deficiency. This solution should be done in conjunction with the pre-calculation noted above in order to avoid unpleasant surprises.

Footnotes

¹ ERCB Directive 006

² ERCB Directive 019

Clause 605

Confusion Over Approval of the Forecast

by Alicia Quesnel and Student-at-Law, Emily Joyce¹

Introduction

Clause 605 of the 1999 Petroleum Joint Venture Association (“PJVA”) model form Construction, Ownership and Operation Agreement (the “CO&O”) deals with Annual Operating Forecasts. Clause 605 requires the Operating Committee to approve the Forecast, which includes all expenditures in accordance with the CO&O. If approval is not received, the Operator must revise the Forecast in accordance with Operating Committee instructions.

The relevant portions of Clause 605 state:

Cl. 605(a) As soon as practicable after the execution hereof, Operator shall submit to the Operating Committee for approval a Forecast for the Forecast Period... If the Operating Committee does not approve a Forecast, or any portion thereof, such Forecast or the portion thereof not approved, shall be revised by Operator in accordance with the instructions of the Operating Committee.

(c) Approval of a Forecast shall constitute approval of all expenditures in accordance with this Agreement, except single Capital Cost expenditures in excess of the single expenditure limit set forth in the Accounting Procedure.

Although Clause 605 is entitled “Forecasts”, Clause 605(c) provides that, with certain exceptions, “approval of a Forecast constitutes approval of all expenditures in accordance with the Agreement”. The language in Clause 605(c) creates an ambiguity. It suggests that all costs, including those costs in excess of the expenditure limitations in the Accounting Procedure, require specific and express approval. However, it does not specifically address what recourse the the Operator has if a Forecast is not approved. Decisions of the Operating Committee are not subject to the dispute resolution procedures found elsewhere in the CO&O — nor should they be — as development and operational decisions should not be imposed on the joint owners by a disinterested third party. What then is the result?

Interpretation Of Clause 605

The intent of Clause 605 is likely to provide a measure of certainty to both Operators and Owners with respect to anticipated expenses for a particular facility for the upcoming 12-month period. However, there



has been no judicial consideration of Clause 605, and it is not addressed in the annotated version of the CO&O. Accordingly, its interpretation will depend on how the drafting language is construed and how industry experience clarifies the intentions of the parties.

The word “shall” as defined in Black’s Law Dictionary is interpreted in a legal context to mean “has a duty to; more broadly, is required to”.² The word “approve” means “to give formal sanction to; to confirm authoritatively.”³ With these interpretations in mind, Clause 605 essentially states that the Operator must submit the Operating Forecast for approval by the Operating Committee and must make any revisions provided by the Operating Committee. However, the Clause provides no guidance with respect to what happens if the Operating Committee does not approve the Forecast, or if the Operator does not agree with the changes suggested, or if the Operating Committee does not suggest any changes.

Some Owners, we understand, have refused to pay for their share of Operating Costs incurred by an Operator if those costs have been incurred under a Forecast that has not been approved. It has been argued that this leaves the Operator with two undesirable options — potentially having to shut in production or continuing to operate and paying the costs of operation itself (subject to the PASC accounting procedure and subject to its contractual duties under Clause 401 to conduct joint operations diligently as a prudent Operator would).

While we agree that ambiguity does exist, we do not believe the Operator is entirely without remedy in these circumstances. While clearly, a proposed new operation or activity may not be commenced, there are other mechanisms available to the Operator. Cl 112 of the 1996 PSAC Accounting Procedure (the “Accounting Procedure”), for example, provides that in addition to operating expenditures allowed by an approved forecast, the Operator is required to incur the following expenditures without approval by the owners:

112. Expenditure Limitations

Unless otherwise specified in the Agreement, the Operator shall make or incur the following expenditures for the Joint Account in addition to operating expenditures allocated by an approved forecast, without approval by the Owners:



- (a) Expenditures including capital expenditures for any single undertaking, the total estimated cost of which is not in excess of _____ dollars (\$_____).
- (b) Expenditures which the Operator deems necessary in emergencies to protect lives or property. ...
- (c) Expenditures for full settlement of each damage claim resulting or arising from Joint Operations not in excess of _____ dollars (\$_____).
- (d) Expenditures which it deems necessary to remedy a violation of an environmental regulation or law. ...

Article II provides that the Operator “shall charge the Joint Account” with certain costs for salaries and wages of its employees, in support of Joint Operations. Cl. 207 of the Accounting Procedure permits the Operator to charge the Joint Account for services, equipment and utilities required for Joint Operations. Cl. 208 entitles the Operator to charge for repair or replacement of joint property made necessary by damages or loss. Additional provisions exist to enable the Operator to charge for taxes, renewal of surface rights and similar payments, insurance premiums, communication equipment, operation and maintenance of camp facilities and the like. The list goes on. The term “Joint Operations” is loosely defined to include activities resulting in “Capital Costs” and “Operating Costs” “and all other activities taken in connection with the Facility, where such activities are conducted for the Joint Account under the terms of this Agreement.” In our view, the term “Joint Operations” as such, includes both activities that require approval of the Owners, as well as activities that do not require the approval of the Owners. For activities that do not require the approval of the Owners, we look both to: (a) clauses such as cl. 112 of the Accounting Procedure, which specifically provides that Owner approval is not required; and (b) clauses that outline the specific mandate and obligations of the Operator under the Agreement, such as C. 401 of the CO&O.

Cl. 401 of the CO&O provides that in the absence of specific instructions from the Operating Committee, the Operator is required to “conduct or cause to be conducted, all Joint Operations, as would a prudent operator under

The current Clause 605 is a legally untested provision in the CO&O. Without modification, the current Clause is unsatisfactory for Operators that are unable to obtain Forecast approval from the Operating Committee.

the same or similar circumstances.” An illustrative list of activities follows. In our view, it is reasonable to assume that costs incurred by the Operator in conducting such “prudent” operations, are costs that are properly allocated to the “Joint Account” and are payable by the Owners accordingly, even if they form part of a Forecast that has not been approved. Cl. 112(a) of the Accounting Procedure, for example, no doubt exists to permit the Operator to make capital maintenance expenditures in order to discharge its duties as a “prudent operator”. Many of the other types of operating costs highlighted above (employees, services, repair and maintenance, insurance), are costs associated with *status quo* maintenance of existing operations. Arguably, to the extent costs are associated with *status quo* maintenance operations, such types of costs are properly charged to the Joint Account and allocable to the Owners, even if they do not form part of an approved Forecast.

Concluding Thoughts And Recommendations

The CO&O is fundamentally a contract that can and should be negotiated to reflect the true intentions of the parties. If Clause 605 is left in substantially the same form, it would be useful to clarify the connection between approval of the Forecast and the ability of the Operator to invoice Owners for Operating Costs.

Outside of the PJVA, it is not uncommon for the Operator to exercise greater discretion in its ability to conduct operations and incur expenses outside of an approved operating and/or capital budget. Many such agreements expressly provide that if the annual budget is not approved, the Operator is deemed to be authorized to continue to expend monies (in an amount equal to the prior years budget or a percentage of it) to complete existing projects and to continue to conduct existing operations and maintenance activities. Although, as we suggest above, this is to a certain extent impliedly contemplated in the CO&O, the scope is unclear. Expressly providing for this result would do much to provide greater certainty to both the Operator and the Owners.

Unless or until such changes are made, an Operator should be cautious when incurring costs that are not part of an approved Forecast and should make every effort, whether on a piecemeal basis or otherwise, to obtain the agreement and/or consent of the Owners to such costs. The Operator should specifically identify for the Owners which costs it considers to “prudent operator” costs or costs incurred under Cl. 112 of the Accounting Procedure.

The current Clause 605 is a legally untested provision in the CO&O. Without modification, the current Clause is unsatisfactory for Operators that are unable to obtain Forecast approval from the Operating Committee. If parties are careful to negotiate and modify the terms of the CO&O to reflect their true intentions, it will be possible to avoid potential impasses. Formal redrafting of the Clause by the PJVA would also help the CO&O to provide more clarity and recourse for parties choosing to use the Agreement as an industry standard.

Footnotes

¹With acknowledgement to Sarah Nossiter and Kristen Dick, formerly of BD&P

²Bryan A. Garner, Editor, Black’s Law Dictionary, 8th Ed., (West Group, 2004) at page 1407

³*Ibid*, at page 111.

Challenging an operator



How Much Information is Required?

By Aaron Rogers and Hazel Saffery

Disputes regarding the performance of an operator or the accuracy of its records are common in the oil and gas industry. However, it is relatively rare for a joint operator to challenge operatorship or seek to replace an operator on the ground that it would be able to conduct operations on more favourable terms and conditions. The recent Alberta decision of *Diaz Resources Ltd. v. Penn West Petroleum Ltd.*¹ deals with a challenge brought by a joint operator and reaches certain conclusions that may come as a surprise to industry participants.

Basis of the Challenge

Diaz Resources Ltd. (“Diaz”) and Penn West Petroleum Ltd. (“Penn West”) each held a 50% working interest in certain oil and gas properties, with Penn West serving as operator of the properties pursuant to a 1990 CAPL Operating Procedure (the “Operating Procedure”).

Diaz served Penn West with challenge notices (the “Challenge Notices”) pursuant to clause 203 of the Operating Procedure, which requires a joint operator to

- (a) show that it is “ready, able and willing to conduct operations for the joint account on more favourable terms and conditions” and
- (b) provide sufficient detail to “enable the receiving parties to evaluate the nature of the challenge notice and to measure the effect the revised terms and conditions would have on joint operations”.

In this regard, Diaz simply indicated that it would not charge the joint account for any costs attributable or related to a production or field office or first level supervisors in the field.

Penn West disputed the sufficiency of the Challenge Notices. Diaz then brought a court application for a declaration that Penn West was deemed to resign as operator and that Diaz

was now the operator as a result of Penn West’s failure to elect, within the time limit provided in the Operating Procedure, to either operate on the terms and conditions proposed by Diaz or resign as operator.

Content of the Challenge Notices

The primary issue for the Court was whether the Challenge Notices contained sufficient information. Despite Diaz’s commitment to reduce certain costs, it was held by the Court that there was “no indication of what those costs include and whether the elimination of those costs would impact costs in other areas”². More significantly, the Court determined that it was not up to Penn West to determine the overall cost impact of the cost reductions proposed by Diaz³, despite that, as operator, it would likely have had the information necessary to do so.

Underlying this finding was the fact that the affidavit filed by Diaz in respect of the proceedings included 9 pages of accounting information with respect to the 36 properties in questions and indicated that Diaz would retain the same contractor currently retained by Penn West, at the same rates. In the opinion of the Court, this information could have been included with the Challenge Notices to permit Penn West to properly evaluate the notices. Ultimately, the Court took the position that the Challenge Notices “must be able to stand on their own”⁴. The Court essentially accepted the argument of Penn West that the whole point of the Challenge Notice is to enable the recipient to understand the impact that the proposed terms and conditions would have on the joint operations.

Capability of the Joint Operator

A secondary issue for the Court was whether Diaz had the ability to assume the duties of an operator. In other words, was Diaz capable of

satisfying the duties imposed upon an operator by the Operating Procedure? In its response to the application by Diaz, Penn West took the position that the Challenge Notices contained no information or discussion regarding Diaz’s ability to conduct operations “in a safe, good and workmanlike manner”.

Although the Court did not find it necessary to make a determination with respect to this issue, it appeared to have some sympathy for the view that a party seeking to replace an operator “must still have the ability to operate in a safe and workmanlike manner”⁵.

Impact of the Decision

The Court’s analysis of the Challenge Notices provides some guidance for joint operators seeking to challenge an operator under an operating procedure, specifically a CAPL Operating Procedure. In such circumstances, a joint operator should ensure that its Challenge Notice contains all relevant information and appropriate analyses of the terms upon which it is prepared to operate. The current operator will not be required to conduct the relevant analysis.

The Court failed to conclusively determine whether the ability of a joint operator to adequately carry out the duties of an operator can be raised by an operator as a defence to a challenge by a joint operator. In light of this, smaller, less experienced and less financially stable joint operators would be well advised to be prepared to respond to such an argument.

Footnotes

¹ *Diaz Resources Ltd. v. Penn West Petroleum Ltd.*, 2010 ABQB 153.

² *Ibid.*, para. 13.

³ *Ibid.*, para. 14.

⁴ *Ibid.*, paras. 15-16.

⁵ *Ibid.*, para. 15.

Bill-24:

Background

On December 2, 2010, *The Carbon Capture and Storage Statutes Amendment Act, 2010* (“Bill 24”) received royal assent and was passed into law. Bill 24 clarifies the basis on which carbon capture and sequestration (“CCS”) is intended to proceed in Alberta and is a very significant step forward for this developing industry. It resolves a number of key uncertainties which were widely acknowledged to be impediments to the adoption of CCS in Alberta on a commercial scale and makes Alberta the first province in Canada to enact a comprehensive legal and regulatory framework to govern CCS operations.

Through amendments to the *Energy Resources Conservation Act*¹, the *Mines and Minerals Act*², the *Oil and Gas Conservation Act*³ and the *Surface Rights Act*⁴, Bill 24 addresses three major areas of uncertainty surrounding CCS:

- Ownership of pore space
- How sequestration rights are to be obtained
- Long-term liability for CCS

Ownership of Pore Space

The ownership of pore space for the purposes of CCS has been a key area of uncertainty for the adoption of CCS. Prior to Bill 24, it appeared likely that the owner(s) of the mineral estate would be treated as owning the pore space left behind as those minerals were produced. This assumption was largely based on common law land ownership principles and the fact that storage rights, analogous although not identical to sequestration rights, are expressly declared to be held by the owner(s) of the mineral estate by section 57(1) of the *Mines and Minerals Act*. In the context of CCS, this assumption gave rise to concerns that obtaining consent for

CCS projects would be difficult, since by nature such projects are likely to involve large areas of land and therefore a large number of potential mineral owners compared to storage.

Bill 24 resolves this uncertainty by declaring that no grant of mineral rights from the Crown (whether in an original grant of freehold mineral title or by way of lease, license or permit) has ever operated to convey title to pore space from the Crown. Further, it is declared that “the pore space below the surface of all land in Alberta is vested in and is the property of the Crown in right of Alberta” (emphasis added). These declarations are broad and are clearly intended to be retroactive.

Although this retroactive declaration of pore space ownership is inconsistent with the previously-held assumption that pore space is owned by the mineral owner(s), Bill 24 expressly provides that the ownership declarations do not result in an expropriation and that no claim for damages is permitted in respect of such provisions. The express denial of expropriation and/or compensation for expropriation is significant and relatively rare, suggesting a desire on the part of the Government of Alberta (“the Government”) to use Bill 24 to remove all major areas of uncertainty surrounding CCS.

Obtaining Sequestration Rights

The result of the declaratory provisions regarding the ownership of pore space in Bill 24 is that any party wishing to sequester CO₂ will have to deal directly with the Provincial Crown. This is a significant outcome for CCS proponents who, absent the provisions of Bill 24, were faced with the prospect of potentially having to obtain the consent of multiple mineral owners and dealing with inevitable holdout issues prior to initiating a CCS project.

Eliminating the Uncertainty

by Justin Jensen, Jerrad Kubik and Aaron Rogers

Pursuant to amendments to the *Mines and Minerals Act* to be implemented by way of Bill 24, no person will be permitted to inject a substance into a subsurface reservoir without being authorized to do so by way of an agreement with the Minister. The basis on which such agreements will be issued has not yet been determined. However, Bill 24 does provide that, unlike leases and licenses for the exploration and production of minerals, agreements for the sequestration of CO₂ will be non-transferrable without the consent of the Minister. Finally, lessees under an agreement for the sequestration of CO₂ will be required to follow all existing regulatory requirements where applicable. This will include the need to obtain well licenses and follow established abandonment and reclamation requirements.

Once an agreement is obtained from the Minister, CCS operators will be required to comply with an approved monitoring, measurement and verification plan, the requirements of which will be detailed by regulation. Careful monitoring and verification of the injection site is vital for CCS operators. This is so because the operator will be required to demonstrate that the CO₂ plume is stable and behaving in a predictable manner, with no significant risk of future leakage, in order to have long-term liability transferred to the Crown, as discussed below. These requirements may potentially increase the life time of a project as plume stabilization may take up to 100 years⁵.

Assumption of Liability for Carbon Sequestration

The final and perhaps most significant aspect of Bill 24 is its provision for the assumption of long-term liability for CCS projects by the Government. The assumption of liability by the government has long been advocated for by industry and commentators. It is seen as the simplest, most effective and most appropriate approach to dealing with the fact that CCS is intended to store CO₂ permanently and obviously longer than any particular lessee or operator could be expected to continue to exist.

Bill 24 provides that, upon the issuance of a “closure certificate” under the *Mines and Minerals Act*, the Crown will become the owner of the sequestered CO₂ and will assume all obligations of the lessee under the CCS agreement, effectively releasing the lessee from any obligations they formerly held. Further, the Crown will indemnify a former lessee against damages claims brought against such lessees.

In order for a closure certificate to be obtained, the lessee must satisfy a number of requirements. These include the proper abandonment of wells and facilities, the completion of reclamation requirements, and compliance with other conditions to be specified in the regulations. A closure certificate will not be issued until the “closure period” (to be specified by the regulation) has passed and until the lessee can establish that the “captured carbon dioxide is behaving in a stable and predictable manner, with no significant risk of future leakage”. This rather subjective requirement provides the Government with a mechanism to avoid assuming liability for CCS projects that have experienced unexpected problems. Practically, however, the Government may be effectively forced to ultimately assume long-term liability for all CCS projects in order to protect the public. We say this as such projects will have been initiated with the understanding that liability would eventually be transferred to the Crown and the former lessees or operators who could otherwise be held accountable for issues will at some point cease to exist.

In order to satisfy the costs of long-term monitoring and liability, Bill 24 also introduces a Post-Closure Stewardship Fund into which lessees under an agreement for the sequestration of CO₂ will be required to pay.

Additional Issues

Despite the clarity that Bill 24 purports to bring to the implementation of CCS projects in Alberta, it does raise a couple of other issues for CCS proponents and landowners.

For CCS proponents, Bill 24 leaves open the question of how enhanced oil recovery (“EOR”) projects implementing CO₂ floods will interact with CCS projects. While the Government has indicated that EOR projects will not be affected by Bill 24, it remains unclear at this point how EOR projects that integrate permanent CO₂ sequestration will be handled. For example, will such projects require an additional agreement under the *Mines and Minerals Act* for the sequestration of CO₂? Will payments into the Post-Closure Stewardship Fund be required? Will the project qualify for the assumption of long-term liability by the Crown? And what additional obligations (such as the requirement to recapture and re-inject produced CO₂) may be placed on EOR projects that intend to permanently sequester CO₂?

Bill 24 may also impact the acquisition of disposal rights on freehold lands. Prior to the enactment of Bill 24, approval for a disposal scheme under the *Oil and Gas Conservation Act* required the consent of the freehold owner. Following the declaration of Crown ownership of pore space in Bill 24, it is arguable that the consent of the freehold owner may no longer be required to the extent that disposal operations are conducted into the Crown-owned pore space contained in subsurface reservoirs. If that is the case, it may represent an unintended consequence of Bill 24, affecting the rights of freehold mineral owners by reducing their control over disposal operations into hydrocarbon-bearing formations that are privately owned.

Of concern to landowners will be the proposed amendment to the *Mines and Minerals Act* to include a mechanism that enables the Minister to enter into an agreement with a lessee for the drilling of an evaluation well to evaluate the suitability of a subsurface reservoir for CO₂ sequestration. This, together with proposed amendments to the *Surface Rights Act* necessary to facilitate this mechanism, will enable an operator of a CCS project to gain access to surface land as necessary for drilling injection wells, connecting such wells to transportation pipelines and conducting required monitoring activities. As a result of these amendments, Bill 24 has created an additional, although necessary, intrusion into the rights of surface landowners.

Footnotes

¹ *Energy Resources Conservation Act*, R.S.A. 2000 c. E-10.

² *Mines and Minerals Act*, R.S.A. 2000 c. M-17.

³ *Oil and Gas Conservation Act*, R.S.A. 2000 c. O-6.

⁴ *Surface Rights Act*, R.S.A. 2000 c. S-24.

⁵ Environmental Protection Agency, *Federal Requirements Under the Underground Injection Control Program for Carbon Dioxide Geologic Sequestration Wells: Proposed Rules 40 CFR parts 144 and 146* at 43495, online: United States Environmental Protection Agency <<http://www.epa.gov/fedrgstr/EPA-WATER/2008/July/Day-25/w16626.pdf>> at 43519

BD&P and Habitat for Humanity

BD&P is thrilled to announce it is house sponsor of the *Women Build 2010*, only the 2nd All Women build in the Calgary Metropolitan area. Numerous women have participated in All Women Builds in other Canadian cities — 42 such builds in Canada since 2006! BD&P is excited to take part in this groundbreaking act of kindness, from women to women.

Construction commenced in November, 2010 in the New Brighton neighbourhood in southeast Calgary. Twenty-one female lawyers and staff from BD&P took part in framing day on Monday, November 15th raising the four exterior walls and framing the main floor of the home. Many new skills were learned and it was with great satisfaction that our BD&P group witnessed the progress made by their cumulative efforts and had the opportunity to meet the new homeowners, a young couple with two young sons. Other women from different organizations in the City of Calgary took part in further completion of the home during the balance of the week.



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