COALBED METHANE: "CONVENTIONAL RULES FOR AN UNCONVENTIONAL RESOURCE"?

JANICE BUCKINGHAM AND PATRICIA STEELE*

Considering the evolution of coalbed methane development in North America, the authors highlight the risks involved at various stages of development. To manage these risks and potentially increase the chance of successful projects, the authors offer suggestions for adapting leases and agreements typically used in the oil and gas industry to reflect the uniqueness of coalbed methane development. The authors also suggest amendments to Alberta's current legislation affecting Crown lands. The authors acknowledge that the issues that arise in the coalbed methane context will change over time as projects are carried out, the industry matures and the legal and regulatory frameworks governing coalbed methane evolve. In providing possible solutions to the current situation, consideration is given to common law principles of ownership of coalbed methane, legislation affecting Crown and freehold lands, typical freehold leases, joint ventures and operating agreements and environmental concerns surrounding coalbed methane development.

Vu l'évolution du développement du méthane de gisements houillers en Amérique du Nord, les auteurs soulignent les risques que comportent les diverses étapes de ce développement. Afin de gérer ces risques et éventuellement d'améliorer les chances de réussite des projets, les auteurs font des suggestions visant à adapter les baux et les ententes typiquement utilisés dans le secteur pétrolier et gazier pour refléter le caractère unique du développement du méthane de gisements houillers. Les auteurs suggèrent aussi des modifications à la législation en vigueur en Alberta relativement aux terres publiques. Les auteurs admettent que les questions qui ressortent du contexte du méthane de gisements houillers changeront avec le temps au fur et à mesure que des projets seront exécutés, que l'industrie évoluera et que les cadres juridiques et réglementaires compétents évolueront eux aussi. En donnant des solutions possibles à la situation actuelle, on envisage le recours aux principes de common law en matière de propriété de méthane de gisements houillers, de législation relative aux terres publiques et franches, aux baux francs, aux coentreprises et aux accords d'exploitation et aux préoccupations de nature environnementale relativement au développement du méthane de gisements houillers.

TABLE OF CONTENTS

* Janice Buckingham, Partner, Bennett Jones LLP, Calgary; Patricia Steele, Associate, Gowling Lafleur Henderson LLP, Calgary. Patricia Steele would like to acknowledge the invaluable contribution made to Parts II and III of this article by John B. Ballem Q.C. and J. Forbes Newman Q.C. of Gowling Lafleur Henderson LLP, Calgary. Janice Buckingham would like to acknowledge the significant contribution made to Part V of this article by Paula Goodall, formerly of Bennett Jones LLP.

I. INTRODUCTION

A combination of market conditions in North America, together with technological advancements, has led to the evolution of coalbed methane (CBM) development to the point where it now comprises approximately 8 percent of natural gas production in the United States. CBM has also attracted significant attention in Canada with 2002 marking the first year for proven CBM reserves.[1]

As the industry has developed, so have the legal and regulatory regimes that govern it. The purpose of this article is to set out some tools that will assist in managing the risks associated with CBM development and allow parties to allocate responsibility consciously for such risks at various stages of development. Part II of this article will consider common law principles related to the ownership of CBM on freehold lands in Alberta, as well as legislation affecting Crown lands. Suggested amendments to the legislation will consider recently enacted legislation in British Columbia that affects both Crown and freehold lands. Part III will then look at the freehold lease and highlight concepts and clauses that warrant additional consideration in the context of CBM. Part IV will discuss conventional joint venture and operating agreements used in the oil and gas industry, determine where they fall short in the context of CBM, and propose alternative forms of agreements and drafting solutions. Finally, Part V will address environmental concerns surrounding CBM development.

II. WHO OWNS THE RIGHTS TO COALBED METHANE?

A. FREEHOLD SPLIT TITLE LANDS — ALBERTA

Simply stated, "freehold lands" are lands which are privately held, that is, by an individual or a company, as opposed to lands held by the Crown in right of Canada or a province. "Freehold ownership" is ownership of an estate in fee simple, such fee simple ownership being the highest form of an estate in land. The bundle of rights associated with fee simple ownership includes mineral ownership, which continues forever.

---

1 Quicksilver Resources Inc. stated that its proved reserves at 31 December 2002 included Canadian CBM. See Pat Roche "Quicksilver To Spend $89 Million (U.S.) in Canada in 2004" *Nickle's Daily Oil Bulletin* (5 March 2004).

In the context of privately-owned land where the mineral rights to coal and natural gas are not held by the same person, called "split title" lands, perhaps the most significant type are railway lands. Following Confederation, the federal government awarded subsidies of surface and mineral rights along railway rights-of-way to encourage the building of a transcontinental railway. The largest part of the 31.6 million acres that were transferred to railway companies is held by Canadian Pacific Railway Co. (CPR). Under the terms of its contract, the CPR was to receive $25 million and land grants totalling 25 million acres. The grants provided for a belt of land 24 miles wide on each side of the railway right-of-way between Ontario and British Columbia. The CPR felt its financial fortunes were tied to settlement and undertook an aggressive colonization program, actively marketing its lands to potential settlers from Europe, Britain, the United States and Eastern Canada. At first, the CPR agreed to transfer to settlers the entire bundle of rights, including rights to mines and minerals. By about 1904, the CPR began to realize that the minerals might be valuable and began to retain certain rights: first coal; then coal and petroleum; then coal, petroleum and valuable stone. By 1912, the CPR had reserved all mines and minerals.[2]

B. DOES COALBED METHANE BELONG TO THE OWNER OF THE COAL OR THE GAS? — CASE LAW ANALYSIS

If rights to coal and natural gas are held by different people, the determination of the party entitled to produce the CBM requires an analysis of long standing principles of oil and gas law, as refined by recent judicial developments.

1. *BORYS V. CPR AND IMPERIAL OIL LTD.* (ALBERTA COURT OF APPEAL)[3]

In *Borys*,[4] the CPR had transferred land to Simon Borys in 1906 reserving "all coal, petroleum and valuable stone which may be found to exist within, upon or under the said land."[5] At the time of the transfer, the reservoir was in its natural state and the hydrocarbons were at initial reservoir conditions. Michael Borys, who became the registered owner of the estate in fee simple in 1947, sought a declaration that he owned all of the natural gas within or under the land.

The Alberta Court of Appeal found that in order to resolve the "sharp contention between the parties as to the meaning to be ascribed to the reservation … we must ascertain the knowledge of the parties at the time of the original agreement and all the surrounding circumstances to determine, as best we may, what the parties to the agreement intended by the reservation."[6] The Court disagreed with the trial court on its findings respecting "petroleum" and whether that term included solution gas and stated:

---

[2] Some of the historical information about the C.P.R. is taken from *Anderson v. Amoco Canada Oil and Gas* (1998), 225 A.R. 277 (Q.B.) [*Anderson*]. *Anderson* referred to *Railways to Resources: The Evolution of PanCanadian Petroleum* (Calgary: PanCanadian Petroleum, 1996), c. 2.

[3] (1952), 4 W.W.R. (N.S.) 481 (Alta. S.C. (A.D.)) [*Borys*].

[4] *Ibid.*

[5] *Ibid.* at para. 484.

[6] *Ibid.* at para. 494.

> The trial judge found that petroleum and natural gas were, by common usage, two different substances, and that conclusion ought not to be disturbed. I am, however, with respect, unable to agree with him that the reservation "petroleum" did not include gas in solution in the liquid as it exists in the earth. What was reserved to the railway company was petroleum in the earth and not a substance when it reached the surface. It is true that, by change of pressure and temperature, gas is released from solution when the liquid is brought to the surface but such a change ought not to affect the original ownership.
>
> In other words, petroleum includes oil and any other hydrocarbons and natural gas existing in its natural condition in strata.
>
> In my opinion, all the petroleum reserved, including all hydrocarbons in solution or contained in the liquid in the ground, is the property of the defendants who are entitled to do as they like with it, subject, of course, to the observance of all relevant statutory provisions and regulations.
>
> All gas not included in the reservation of petroleum as indicated is the property of the plaintiff.[7]

The Court of Appeal also held that the petroleum reservation necessarily included the right to produce petroleum and that the CPR could use all reasonable means to extract the petroleum, even if this resulted in wasting some of Borys' gas. This point was addressed by the Alberta Court of Appeal in *Alberta Energy v. Goodwell Petroleum*[8] and will be re-visited later in this article.

2. *BORYS V. CPR AND IMPERIAL OIL LTD.* (PRIVY COUNCIL)[9]

The decision in *Borys* was appealed to the Privy Council, which confirmed the Court of Appeal's decision as being correct in all respects.

3. *ANDERSON V. AMOCO CANADA OIL AND GAS* (ALBERTA COURT OF QUEEN'S BENCH)[10]

In *Anderson*, when faced with the issue of whether evolved gas belonged to the petroleum or the natural gas owner, the trial judge concluded that the determination of ownership turned on an analysis and interpretation of *Borys*. Justice Fruman (as she then was) also found that Canadian courts had yet to settle on a theory of oil and gas ownership, but that it was unnecessary to do so in this case because the petroleum and non-petroleum owners derived their ownership rights from the CPR reservation. She went on to find that "[t]he only reasonable ownership theory on which to proceed is that the petroleum reserved is owned as a fee simple interest *in situ* by the petroleum owner and the gas is owned as a fee simple interest *in situ* by the non-petroleum owner, subject to the rule of capture as modified by conservation legislation and subject to the petroleum owner's right to use the gas in recovering petroleum."[11] The plaintiffs had argued that the Court's decision must be consistent with the rule of capture which, in this case, meant that changes in phase condition

---

7 *Ibid.* at para. 494.
8 2002 ABCA 251 [*Goodwell*].
9 (1953), 7 W.W.R. (N.S.) 546 (J.C.P.C.).
10 *Supra* note 2.
11 *Ibid.* at para. 101.

in one tract of land would lead to a change in ownership under split title circumstances. Prior to concluding that the rule of capture was not relevant to a determination of ownership in split title cases, Fruman J. stated:

> The rule of capture permits landowners to drain away and capture substances from adjoining lands. It is primarily a rule of non-liability and, in an ownership jurisdiction, a qualification on ownership.... *Borys* confirmed that the rule of capture applies in Canada:
>
> > If any of the three substances is withdrawn from a portion of the property which does not belong to the appellant but lies within the same container and any oil or gas situated in his property thereby filters from it to the surrounding lands, admittedly he has no remedy. So, also, if any substance is withdrawn from his property, thereby causing any fugacious matter to enter his land, the surrounding owners have no remedy against him. The only safeguard is to be the first to get to work, in which case those who make the recovery become owners of the material which they withdraw from any well which is situated on their property or from which they have authority to draw.[12]

Perhaps the most noteworthy aspect of *Anderson* with respect to CBM development was the analogy that was drawn by counsel for one of the plaintiffs who relied on American case law involving a phase severance of coal and CBM as authority for establishing ownership of CBM based on its location at the time of recovery, that is, at the surface. Justice Fruman rejected this argument and highlighted the inconsistencies in CBM case law among various states in the United States, as well as the difference in ownership theories between Canada and the United States.

4. *ANDERSON V. AMOCO CANADA OIL AND GAS* (ALBERTA COURT OF APPEAL)[13]

As far as the oil and gas industry is concerned, the implications of *Anderson C.A.* can be neatly summarized in the following statement by the Court of Appeal in its conclusion:

> We conclude that *Borys* is authority for the proposition that ownership must be determined as at the time of the reservation. In this appeal, as in *Borys*, the hydrocarbons were in initial reservoir conditions at the date of the reservation. Phase changes that occur subsequently are irrelevant to ownership. Accordingly, the situation here is indistinguishable from *Borys* and ownership must be determined at initial reservoir conditions.
>
> The trial judge adopted the correct analytical framework when addressing ownership of oil and gas on split title lands. Her finding that evolved gas belongs to the petroleum owner was correct and was consistent with the principles outlined in *Borys* and in *Prism*.[14]

5. *BARNARD-ARGUE-ROTH-STEARNS OIL AND GAS CO., LTD. V. FARQUHARSON* (PRIVY COUNCIL)[15]

Another case relevant to the ownership issue is *Barnard*. This was a decision of the Privy Council in 1912 on appeal from the Ontario Court of Appeal involving the interpretation of

[12] *Ibid.* at para. 130 [footnotes omitted].
[13] (2002), 312 A.R. 116 (C.A.)[*Anderson* C.A.].
[14] *Ibid.* at paras. 54-55.
[15] [1912] 5 D.L.R. 297 (J.C.P.C.) [*Barnard*].

a reservation of mines and minerals in a conveyance of land. By deed dated 22 January 1867, the appellant land company granted to the respondent's predecessor in title all of their right, title and interest in the land, "excepting and reserving to the company, their successors and assigns, all mines and quarries of metals and minerals, and all springs of oil in or under the said land, whether already discovered or not, with liberty … to and for the said company … to search for, work, win, and carry away the same."[16] The sole question for decision was whether, having regard to the time at which the instrument was executed and the facts and circumstances then existing, the parties to the deed intended to except from the grant the natural gas contained in certain strata underlying the lands.[17] The following excerpt from the Court's decision is worth noting:

> In one sense, natural gas is … a mineral, in that it is neither an animal nor a vegetable product, and all substances to be found on, in or under the earth must be included in one or other of the three categories of animal, vegetable, or mineral substance. It is obvious, however, for several reasons, that in this clause of the grant the word "minerals" is not used in this wide and general sense. First, because two substances are expressly mentioned in the clause which would be certainly covered by the word "minerals" used in its widest sense.… Secondly, because the words "all mines and quarries of metals and minerals," coupled with the words "search for, work, win, and carry away the same," do not seem to be applicable to a thing of the nature of this gas, obtainable in the way it is obtained; and thirdly, because of the nature of the relation which exists between this gas and "rock oil … " excepted in the grant of the function which the gas performs in winning, working, or obtaining the oil from these springs; and fourthly, *because of the state of knowledge at the date of this deed and the way in which gas of this kind was then regarded and treated.*
>
> …
>
> It is clearly established by the evidence that this gas is not volatilized rock oil, nor is rock oil condensed natural gas.
>
> The gas is not an exhalation of the oil, nor is it held in solution by the oil to any considerable extent. The gas and oil are in their chemical composition no doubt both hydro-carbons, but they are distinct and different products, and it, therefore, could not be contended successfully, their Lordships think, that the words "springs of oil" cover this natural gas, simply because both are found in some cases to impregnate the same subterranean porous stratum.… [I]t was proved at the hearing before the Chancellor that oil mining leases only began to be made by the Canada Company in the year 1863.
>
> At the date of this deed, January 22, 1867, the winning of mineral oil through gas wells was a comparatively new industry. This natural gas, according to the witness, did not become commercially valuable till the year 1880. And, according to the evidence of others … some gas was always found where oil was found, but the gas was regarded as a dangerous and destructive element to be got rid of as it best could. It did not begin to be utilized till the year 1890, over 20 years after the date of the deed. *The inference to be drawn [from this evidence] appeared to their Lordships to be that the idea of preserving the ownership of this product, whose presence was regarded in 1867, and for many years after, as a dangerous nuisance, never occurred to the parties to the deed [of January 22, 1867].*[18]

16 *Ibid.* at 298.

17 *Ibid.* at 300.

18 *Ibid.* at 298-300 [emphasis added].

After considering the knowledge of the parties in 1867, being the time of the reservation, and the scientific characteristics of natural gas compared to oil, the Court found that a reservation of mines and minerals did not include natural gas.

In light of the fact that coal miners were responsible for venting or otherwise managing CBM as a by-product of mining when it was not considered to be an asset, some have argued that coal miners should now be entitled to CBM as compensation for their past efforts. In light of *Barnard*, however, it is not possible for someone who regarded a substance as a nuisance to preserve its ownership without specific language to that effect.

6. THE POWER OF THE ALBERTA ENERGY AND UTILITIES BOARD IN SPLIT TITLE SITUATIONS

While the powers of the Alberta Energy and Utilities Board (AEUB) in regulating the oil and gas industry are legislated, a clarification of its authority in split title situations is about to become part of the common law.

An appeal of the decision by the AEUB in *Goodwell Petroleum Co. Ltd. Request to Shut In Bitumen Wells Wabiskaw-McMurray Oil Sands Deposit Athabasca Area — Brintnell Sector*[19] was recently heard by the Alberta Court of Appeal.[20] Although the case obviously dealt with the issue of competing mineral ownership in the context of natural gas over bitumen, the treatment by the AEUB of the split title issue and the views of the Court of Appeal in the leave to appeal decision could very well indicate the approach a court would adopt in a dispute between a coal and a natural gas owner. The facts, as they appear in the leave to appeal decision, are described below.

At the time of the AEUB decision, Goodwell Petroleum Co. Ltd. (Goodwell) held the petroleum and natural gas rights on certain Alberta lands. Amber Energy (AEC) originally held the bitumen rights for the same lands and drilled and operated 16 horizontal bitumen wells. In October 1998, AEC acquired the bitumen interests and operating wells. Goodwell claimed that a significant portion of its initial gas-cap gas was being produced with the bitumen, and had attempted to negotiate compensation with AEC for past production and a sharing agreement for future production. After failing to reach an agreement, Goodwell instituted legal proceedings that are currently ongoing. Goodwell also applied to the AEUB to shut-in the 16 horizontal bitumen wells operated by AEC, claiming that they had been producing large volumes of the initial gas-cap gas. The AEUB noted that it had issued a licence to AEC to drill and produce crude bitumen and that any production of gas-cap gas would be in breach of its licence. Accordingly, it ordered that four horizontal bitumen wells be shut in until such time as AEC had obtained the full rights of production.

AEC's application for leave to appeal was based on two grounds. First, it contended that the AEUB's decision was patently unreasonable because it imposed a condition that AEC could not fulfill on reasonable commercial terms. By shutting in the wells until an agreement

19 (31 March 2000), AEUB Decision 2000-21 (AEUB).

20 *Alberta Energy v. Goodwell Petroleum Co. Ltd.*, 2003 ABCA 277.

could be reached, the AEUB had heavily weighted the stakes in favour of Goodwell, the gas-cap holder and placed AEC in an untenable negotiating position.

Second, AEC argued that the AEUB had erred in law when it ordered that four horizontal bitumen wells be shut-in until AEC obtained the full rights of production. Counsel for AEC cited *Borys*, pointing out that the Privy Council had found that the holder of the natural gas interest could not prevent the holder of the petroleum interest in the same tract from producing its leased substances, even though some of the gas-cap gas would incidentally be produced and wasted. Counsel set out the following quote from *Borys*: "Even if it be conceded that the respective rights of the two parties are to work for and recover each his own property, [...] it does not follow that neither can act without the consent of the other and that only by mutual agreement can they work at all."[21]

Counsel also noted that the Privy Council had found that incidental production of natural gas was allowed, provided modern operating methods were followed in the production of the petroleum and the provisions of relevant statutes and regulations were observed.

Counsel for the AEUB acknowledged *Borys*, but stated that it was based on the wording of the specific C.P.R. grant and that the same considerations may not apply in a competition between the bitumen holder and gas-cap holder under the leases that apply in the present circumstances. Furthermore, counsel argued that the regulatory scheme in Alberta qualified the unfettered right of an oil producer to deplete significant gas volumes belonging to another, both for conservation and ownership reasons.

Goodwell was represented at the leave application, but took no position.

In granting leave to appeal, the Court of Appeal acknowledged that in its enabling legislation the AEUB had both general and specific powers to effect the conservation and orderly and efficient development of energy resources. It also acknowledged that one of the purposes of the *Oil and Gas Conservation Act* was to afford each owner the opportunity of obtaining the owner's share of the production of oil or gas from any pool.[22] The Court went on to state that it found that the legislation was not clear with respect to the AEUB's power to determine the rights of interest holders in a split title situation or to shut in wells until such time as the bitumen holder had the contractual right to produce gas-cap gas.

Leave to appeal was then granted on the following questions:

1. Did the Board err in law or jurisdiction in determining that AEC's right to produce leased substances under its oil sands leases did not include any production of initial gas-cap gas?

2. Did the Board err in law or jurisdiction in shutting-in wells until such time as AEC had "the full rights to produce" the gas-cap gas and by encouraging it to enter into a production and cost sharing agreement?[23]

---

21 *Goodwell*, *supra* note 8 at para. 9 [citations omitted].
22 R.S.A. 2000, c. O-6, s. 4(d).
23 *Supra* note 8 at para. 14.

The analogy between the owners of gas-cap gas and bitumen in *Goodwell* and the owners of coal and natural gas in CBM development could not be more acute. In fact, the decision in *Goodwell* will undoubtedly have a direct impact on the relationships between coal and natural gas owners in CBM developments where split title exists, regardless of whether ownership legislation has been passed. For example, according to counsel for AEC, in reliance on *Borys*, neither a coal owner nor a natural gas owner would be able to prevent the rightful owner of the CBM from producing it by refusing to enter into an agreement. Consequently, the AEUB may be powerless to enforce its existing policy that requires such an agreement to be in place prior to a well licence being issued or production commencing.

7. A QUESTION OF SCIENCE AND LAW

As we can see from the case law, resolution of ownership issues surrounding CBM will require an understanding of its physical and chemical characteristics. CBM, which is composed primarily of methane gas, is created as a byproduct of coal formation.[24] That process began millions of years ago when, according to geologic theory, a dramatic change in the earth's climate caused the swamps and lush plant life to die and over time to become buried in layer upon layer of sediment. Under the pressure and weight of this sediment, the dead vegetation was gradually transformed to coal, ranging from lignite, peat and humus, which are generally found near the surface, to anthracyte, bituminous and subbituminous coals, which are usually found at greater depths.[25]

Methane gas is generated during two stages of the coalification process. The initial, or biologic phase, begins at low temperatures (70°F - 120°F) and generates methane, but very little of the gas generated remains trapped in the coal. The second, or thermogenic phase, which begins at higher temperatures (200°F and above) as the coals are buried more deeply, generates large amounts of methane, carbon dioxide, nitrogen and water. A higher percentage of the substances generated in this phase remain trapped in the coal and become the target of CBM developers.[26]

It is generally accepted that CBM is stored in the coal in two ways. It is either absorbed onto the surface of the micropore system of the coal or is present in the macropore system, also known as "cleats," of the coal, either as a free gas or dissolved in water.[27] The pressure of the water formed during methane generation traps the methane in the coal. In the case of adsorption onto the surface of the micropore system, the hydrostatic pressure actually causes the methane molecules to bond to the carbon matrix of the coal. Because the micropore system of the coal has such a large internal surface area, and methane molecules can be tightly packed due to their relatively small size, coal can hold two to three times as much gas as conventional reservoirs. The amount of coalbed gas contained in a coal seam or bed depends upon a number of geologic factors, including the thickness and extent of the coal

---

24 J.E. Fassett, "Coal-bed Methane — A contumacious, free-spirited bride, the geologic handmaiden of coal beds" in John C. Lorenz & Spencer G. Lucas, eds., *Energy Frontiers in the Rockies* (Albuquerque: Albuquerque Geological Society, 1989) 131 at 131.

25 "Freeing Methane Molecules Trapped in Coal" *Gas Research Institute Digest* 8:1 (January/February 1985) 5 at 5.

26 *Ibid.* at 131.

27 *Ibid.* at 133.

bed, the rank of the coal, the thickness of the overburden and the hydrostatic pressure. Generally, the coals with a rank of high volatile bituminous B or higher contain the most methane.[28]

As for its chemical composition, CBM is made up of methane (95 percent), trace amounts of higher hydrocarbons such as ethane and propane and less than 3 percent each of nitrogen gas and carbon dioxide.[29] Hydrogen sulfide is seldom encountered and, with a typical heating value of 1,000 Btu, CBM comes out of the ground practically ready for the pipeline.[30] Because methane is the primary component of natural gas produced from coalbeds, CBM can be used interchangeably with natural gas. There are distinct chemical and isotopic differences, however, that can be used to identify the source rock of the gas.[31]

An application of legal principles to the science of CBM seems to raise questions rather than resolve the issue of whether CBM is a form of natural gas or an intrinsic part of coal. For example, under initial coal seam conditions, would CBM be considered a chemical part of coal, the emergence of which constitutes a phase change? Is CBM an "exhalation" of coal? To the extent that CBM is capable of existing freely in fractures within the coal seam, simply adhering to the internal surface of micropores within the coal as a result of pressure, does that mean CBM is gaseous in its natural state?

Put another way, would it be accurate to draw an analogy between gas in solution and CBM in coal? Or would it be better to equate coal to reservoir rock and to characterize the CBM as free gas that would escape upon release of pressure?

While the answers to these questions may not be simple, it is clear that any question regarding the ownership of CBM rights coming before a court will necessarily require a scientific determination as well as a legal one. *Anderson* and *Barnard* give examples of the type of analysis a court would undertake to reach a scientific conclusion, and *Borys*, *Anderson* and *Barnard* make it absolutely clear that the knowledge of the parties at the time of the grant or reservation would be relevant.

8. PRINCIPLES FOR FREEHOLD MINERAL RIGHTS

Based on the foregoing, we can say that the following principles would be relevant in the determination of CBM mineral rights on freehold lands:

- Ownership of a mineral right must be determined at the time of the reservation or grant.

---

28 *Ibid.* at 132.

29 C.T. Rightmire, "Coalbed Methane Resources" in Craig T. Rightmire, Greg E. Eddy & James N. Kirr, eds., *Coalbed Methane Resources of the United States* (Tulsa, Oklahoma: The American Assoication of Petroleum Geologists, 1984) 1 at 6.

30 *Supra* note 24 at 5.

31 Dudley D. Rice *et al.*, "Identification and Significance of Coal-Bed Gas, San Juan Basin, Northwestern New Mexico and Southwestern Colorado" in James E. Fasset, ed., *Geology and Coal-Bed Methane Resources of the Northern San Juan Basin, Colorado and New Mexico* (Denver: Rocky Mountain Association of Geologists, 1988) 51.

- The knowledge of the parties at the time of the original agreement is relevant.
- Where it can be ascertained that a particular vernacular meaning is attributed to words, that meaning must prevail over a scientific meaning.
- Petroleum does not have to be reduced to possession to become the subject of ownership.
- A petroleum reservation includes the right to produce petroleum, and all reasonable means to extract such petroleum may be used, even if gas owned by the non-petroleum owner is used in the process.
- Canadian courts have not committed to a particular theory of oil and gas ownership.
- Phase changes that occur subsequent to the time ownership is determined are irrelevant.
- The relevance of American case law is significantly diminished by the fact that it is inconsistent and is dependent on the ownership theory adopted in a particular state.
- Any question regarding the ownership of CBM rights coming before a court will necessarily require a scientific determination, as well as a legal one.

C. CROWN LANDS — ALBERTA

In Alberta, about 90 percent of all minerals are owned by the province, which acquired jurisdiction over its mineral resources in 1930. Pursuant to AEUB Information Letter IL 91-11 (IL 91-11),[32] CBM is considered to be a form of natural gas by the AEUB and the Alberta Department of Energy (DOE). As a result, all statutes and regulations that pertain to natural gas also pertain to CBM.

1. *ALBERTA ENERGY STATUTES AMENDMENT ACT, 2003*[33]

After introduction to the Alberta legislature on 3 March 2003, the *Energy Statutes Amendment Act, 2003* received royal assent on 16 May 2003, but has yet to be proclaimed into force.

As for the impact of the *ESA Act* on CBM development, the amendments to the *Mines and Minerals Act*[34] appear in their entirety in the italicized text below:

Part 2

Coal

Rights granted by lease

67(1) A coal lease grants the right to the coal that is the property of the Crown in the location in accordance with the terms and conditions of the lease *but, subject to subsection (2), does not grant any rights to any natural gas, including coalbed methane.*

(2) The Minister, on the recommendation of the Energy Resources Conservation Board that it is necessary to do so for safety or conservation reasons, may authorize the lessee of a coal lease to recover natural gas, *including coalbed methane*, contained in a coal seam in the location of the coal lease.[35]

---

[32] Alberta Energy and Utilities Board, Information Letter IL91-11, "Coalbed Methane Regulations" (26 August 1991).

[33] S.A. 2003, c. 18 [*ESA Act*].

[34] R.S.A. 2000, c. M-17 [*Mines and Minerals Act*].

[35] *Ibid.* at s. 67 [emphasis added].

Some would argue that the *ESA Act* falls short of an ideal legislative solution, particularly in comparison to the British Columbia *Coalbed Gas Act*.[36] Notably absent from the *ESA Act* is a definition for "coalbed methane" or an amendment to the definition of "natural gas" to explicitly include CBM. The definition of "natural gas" in the *Mines and Minerals Act* is tied to a gas-oil ratio, however, which effectively, if not explicitly, includes CBM.[37]

Nor does the *ESA Act* state that the provisions related to CBM are retroactive. Theoretically, this would make it easier for lessees of existing Crown coal agreements to argue that this law does not apply to them. The implications of that position regarding CBM ownership may not be compelling; however, in light of IL 91-11, s. 67(2) of the *Mines and Minerals Act*, which permits recovery of natural gas from a coal seam, by order, by a coal lessee for safety or conservation reasons only, and the regulatory incorporation provisions in Crown agreements which cause a lessee to be bound by statutes and regulations passed subsequent to the time that it acquired its interest in the Crown agreement.

Perhaps the most distinctive aspect of the *ESA Act*, when comparing it to the *Coalbed Gas Act*, however, is the fact that its references to CBM apply only to Crown lands, leaving the ownership issue regarding freehold lands completely unresolved.

2. AN ALTERNATIVE TO THE *ENERGY STATUES AMENDMENT ACT*

In the absence of judicial determination on a case-by-case basis, the ownership of CBM as between the holder of the coal and natural gas rights on freehold split title lands will remain uncertain.

An example of the evolution of legislation in a fact situation that could parallel CBM development may be found in a decision by the Supreme Court of Canada in *Western Minerals v. Gaumont*.[38] This case involved an appeal from the Appellate Division of the Supreme Court of Alberta in a matter regarding the ownership of sand and gravel. The appellant, Western Minerals Ltd. (Western Minerals), held a certificate of title as the registered owner in fee simple under the *Land Titles Act* (Alberta)[39] of all mines, minerals, petroleum, gas, coal and valuable stone in or under two quarter sections of land over which the respondents, Gaumont and Brown, were the respective owners of the surface rights. Western Minerals sued for a declaration that it was the registered and equitable owner of all minerals and/or valuable stone, including the sand and gravel within, upon or under the said lands. Judgment was initially given in favour of Western Minerals. Following the filing of notice of appeal by Gaumont and Brown, *The Sand and Gravel Act* (Alberta)[40] came into force providing that, as to all lands in the province, the owner of the surface of land is and shall be deemed at all times to have been the owner of and entitled to all sand and gravel on the surface of that land. The Appeal Court allowed the appeal and the Supreme Court of

---

36. S.B.C. 2003, c. 18 [*Coalbed Gas Act*].
37. *Supra* note 34, s. 80(2).
38. [1953] 1 S.C.R. 345 [*Gaumont*].
39. R.S.A. 2000, c. L-4.
40. The *Sand and Gravel Act* no longer exists as a separate piece of legislation. Its provisions now form part of the *Law of Property Act*, R.S.A. 2000, c. L-7 [*Sand and Gravel Act*].

Canada dismissed the subsequent appeal, with the result that Gaumont and Brown were found to be the owners of the sand and gravel.

In finding the *Sand and Gravel Act* to be within the legislative jurisdiction of the province by virtue of head 13 of s. 92 of the *British North America Act* (now, the *Constitution Act, 1867*),[41] the Supreme Court described the case as being one in which the boundary between property rights, depending upon the scope to be given general words in common parlance, was somewhat vague and uncertain. To avoid widespread disruption of what were thought to be settled interests, the Supreme Court held that the legislature could, quite legitimately as a precautionary measure, resort to a declaration of pre-existing law.

The *Act*, as set out in the decision of the Court of Appeal of Alberta in *Western Minerals Ltd. v. Gaumont, Western Minerals Ltd. v. Brown* is reproduced below:

> On April 7, 1951, the Legislature of Alberta passed an Act [*The Sand and Gravel Act, 1951*, c. 77] in the following words:
>
> > Whereas in an action in the Supreme Court of Alberta between Western Minerals Limited and ... Joseph Albert Gaumont ... and James Warren Brown ... it was adjudged that the plaintiffs who were the owners of minerals were entitled to sand and gravel and that the defendants who were the owners of the surface of land were not entitled to the said sand and gravel; and
> >
> > Whereas the learned trial judge made it clear in his judgment that his decision did not affect ownership of sand and gravel in Alberta generally but only that contained in the particular land involved in the action, and that the ownership of sand and gravel in any particular case is purely a question of fact to be determined on the evidence introduced in that case; and
> >
> > Whereas the ownership of sand and gravel becomes a matter of doubt and uncertainty if it is dependent on whether evidence indicates that it constitutes the ordinary soil or subsoil of the district or that its occurrence is rare and exceptional and on whether it is regarded as a mine, mineral or valuable stone in the vernacular of the mining world, the commercial world and land owners at the time of any disposition in question, and
> >
> > Whereas it appears desirable in the public interest to resolve these doubts and uncertainties and to allay fears:
> >
> > Therefore His Majesty, by and with the advice and consent of the Legislative Assembly of the Province of Alberta, enacts as follows:
> >
> > 1. This Act may be cited as 'The Sand and Gravel Act'.
> >
> > 2. This Act applies to all lands in the Province and to the owners thereof, including the Crown in the right of the Province and the lands owned by the Crown in the right of the Province.

---

41 (U.K.), 30 & 31 Vict., c. 3, reprinted in R.S.C. 1985, App. II, No. 5.

> 3. The owner of the surface of land is and shall be deemed at all times to have been the owner of and entitled to all sand and gravel on the surface of that land and all sand and gravel obtained by stripping off the overburden, excavating from the surface, or otherwise recovered by surface operations.
>
> 4. (1) The sand and gravel referred to in section 3 shall not be deemed to be a mine, mineral or valuable stone but shall be deemed to be and to have been a part of the surface of land and to belong to the owner thereof.
>
> (2) Notwithstanding any patent, title, grant, deed, notification, conveyance, lease, licence, agreement, disposition or other document heretofore or hereafter issued or made that contains or reserves mines, minerals or valuable stone, the owner of the mines, minerals or valuable stone in any land shall not be entitled to the sand and gravel in that land referred to in section 3 as against the owner of the surface of such land.
>
> 5. Where sand and gravel has been dealt with or removed from any land prior to the coming into force of this Act by the owner of the mines, minerals or valuable stone, or by any person claiming through him, acting in good faith and in the honest belief that he was entitled thereto, the owner of the surface of the land shall not have any right of action for damages or for compensation by reason of such dealing with or removal of the sand and gravel prior to the coming into force of this Act, other than such action as he would have had if the person removing the sand and gravel was the owner of it.
>
> 6. This Act shall come into force on the day upon which it is assented to.[42]

The evolution of a *Gaumont*-type fact situation in the context of CBM would be less than startling and bordering on predictable. This apparently was the view of the Province of British Columbia, as revealed by the similarities between the *Coalbed Gas Act* and the *Sand and Gravel Act* (Alberta).

Although it has taken steps in the past to clarify ownership rights by passing declaratory legislation, whether the Province of Alberta will do so with respect to freehold lands to facilitate CBM development remains to be seen.

III. THE FREEHOLD LEASE

Although conventional natural gas and CBM share many common drilling and exploration technologies, the production of these two resources is different in many respects. Perhaps the most dramatic difference relates to the volume of produced water. In a conventional natural gas well, a relatively large volume of natural gas is typically produced, along with a small amount of water. In a CBM well, although production from dry coals is possible, a large volume of water may have to be produced at the outset, with little or no natural gas. This phase of water production depressures the coal seam and may last for a period of several months to years. Once a CBM well begins producing, the production rate is typically much lower than a conventional natural gas well.

---

42 [1952] 1 D.L.R. 143 (Alta. S.C. (A.D.)) at 150 [*Gaumont* C.A.].

The lengthy depressuring process and lower rate of production impact common industry agreements in various ways. This portion of the article will examine the impact on the freehold lease.

A. GRANTING CLAUSE

The definition of leased substances in both the *1991 Form of Alberta Petroleum and Natural Gas Lease*[43] and the *1999 Form of Alberta Petroleum and Natural Gas Lease and Grant*[44] is substantially the same and is defined to be: "all petroleum, natural gas and related hydrocarbons (except coal), and all materials and substances (except valuable stone), whether liquid, solid or gaseous and whether hydrocarbons or not, produced in association with petroleum, natural gas or related hydrocarbons or found in any water contained in any reservoir."[45]

CAPL 99 adds the words "but only to the extent that the foregoing are included in the Certificate of Title."[46] While the DOE and EUB consider CBM to be a form of natural gas, the ownership issue as it relates to freehold lands is still uncertain. As a result, it is recommended that a lease be taken from the owner of the coal rights as well as the natural gas rights, or an agreement be entered into among all relevant parties pursuant to which the rights to CBM by the lessee will be secure. The granting clause in *CAPL 91* and *CAPL 99* would have to be amended specifically to include CBM from the owners of both mineral rights and to include coal in the lease from the owner of the coal rights.

The granting clause under both *CAPL 91* and *CAPL 99* provides that the primary term is for a stated number of years. Historically, it was common for primary terms to be for five or ten years. Over time, this has evolved to a period of no more than two years.

Given the potentially lengthy depressuring phase, a primary term of five years would arguably be more appropriate in a lease for CBM rights.

B. *HABENDUM* CLAUSE

Both *CAPL 91* and *CAPL 99* provide that the lease continues beyond the expiry of the primary term "so long thereafter as operations ... are conducted upon the said lands, the pooled lands or the unitized lands, with no cessation, in the case of each cessation of operations, of more than 90 consecutive days."[47]

CAPL 91 defines "operation" to be any of the following:

(i) drilling, testing, completing, reworking, recompleting, deepening, plugging back or repairing a well or equipment on or in the said lands or injecting substances by means of a well, in search for or in an

---

43 Canadian Association of Petroleum Landmen, 1991 [*CAPL 91*].
44 Canadian Association of Petroleum Landmen, 1999 [*CAPL 99*].
45 *CAPL 91*, *supra* note 43; *CAPL 99*, *ibid.*
46 *CAPL 99*, *ibid.*
47 *CAPL 91*, *supra* note 43; see also *CAPL 99*, *ibid.*.

endeavour to obtain, maintain or increase production of any leased substance from the said lands, the pooled lands or the unitized lands;

(ii) the production of any leased substance;

(iii) the recovery of any injected substance; or

(iv) any acts for or incidental to any of the foregoing.[48]

The definition of operations in *CAPL 99* is substantially the same, other than the addition of operations which are deemed to be operations pursuant to the shut-in well clause.

The question then becomes whether the term "operations" would include the depressuring phase of a CBM well. It is unclear, at best, whether a well that was producing water only and not leased substances would be considered to be subject to "operations." If it were found that depressuring did not constitute "operations" and if the period of cessation of operations had been more than 90 consecutive days after the end of the primary term, the lease would terminate.

Consequently, it is recommended that the definition of "operations" be expanded specifically to include the depressuring phase of a CBM well, whether at the point of initial production or after it has been shut in and production has re-commenced.

C. SUSPENDED WELL CLAUSE

Technical difficulties associated with the production of CBM will undoubtedly lead to many situations where the lessee will find it necessary to shut in a well and rely on the suspended well clause for the continuation of the lease. Such situations could include the absence of appropriate production and disposal facilities, lack of an available market, or technical problems.

The CAPL leases require that in order for the shut-in clause to apply, the shut-in well must be "capable of producing the leased substances"[49] or "capable of production of the Leased Substances."[50] Unfortunately, the meaning of production capability is undefined under both *CAPL 91* and *CAPL 99*. This leads to the question of whether a CBM well that is shut-in is capable of production, given that depressuring will undoubtedly be necessary when the well is put back in production.

The United States experience may be helpful in assessing whether such a well would be considered capable of production. The U.S. courts have defined "production" to mean production in paying quantities. This has been further refined by the Texas Court of Appeal, which found a well to be capable of production when it was subsequently turned on only if it was able to produce leased substances without further equipment or repair.[51] This approach in determining whether a well is capable of production places a heavy burden on the lessee if a well is shut-in and requires further depressuring before it is placed on production.

---

48 *CAPL 91*, *ibid.*, s. 1(g).

49 *CAPL 91*, *supra* note 43, s. 3.

50 *CAPL 99*, *supra* note 44, s. 3.

51 Gregory R. Danielson, "Lease Maintenance and the Development of Coalbed Methane," (2000) 46 Rocky Mt. Min. L. Inst. 8-1 at 8-27.

Although the phrase "capable of production" is not defined in the CAPL leases, it is unclear whether Canadian courts would adopt the same test applied by U.S. courts. Out of an abundance of caution, it is recommended that the suspended well clause in *CAPL 91* or *CAPL 99* be modified to include a definition of "capable of production" that explicitly permits a depressuring stage when a shut-in well is later reopened for production.

D. OFFSET WELLS

The offset well clause in *CAPL 91*[52] and *CAPL 99*[53] requires the lessee to do one of four things within six months of drilling an off-setting well capable of commercial production. Those options are:

(a) to commence the drilling of a well on the said lands to offset the production from the adjoining lands;
(b) to pool or unitize the applicable portions of the said lands;
(c) to surrender all or any portions of the said lands adjoining the offset well; or
(d) to elect in writing to pay the lessor a royalty equal to the royalty the lessor would have received had the offset well been drilled on the said lands.[54]

As a practical matter, the lessor may want to consider seriously the option of paying the royalty. This option would be preferable in the event that initial commercial production from the offset well was low, with the result that the royalty payable by the lessee would be small. This would enable the lessee effectively to take a wait and see approach to determine the ultimate productivity of the offset well. This option is available under both CAPL leases and would allow the lessee subsequently to stop paying the royalty and to elect to pursue one of the other three options once more information is available with respect to the offset well.

It is also worth noting that *CAPL 91*[55] defines an offset well as a well drilled in a spacing unit that laterally joins the said lands, whereas *CAPL 99*[56] includes wells drilled in spacing units that laterally and diagonally adjoin the subject lands. Due to the technical challenges and increased costs of drilling CBM wells, the lessee may wish to utilize *CAPL 91* or to restrict *CAPL 99* to laterally adjoining spacing units only.

Finally, regardless of which CAPL lease is used, it would be useful to have the six month obligation date extended. The lessee could argue that such a modification would be appropriate given the longer productive life of a CBM well and the slower rate at which a pool would be drained.

E. ROYALTIES

The royalty clauses in both *CAPL 91* and *CAPL 99* permit the lessee to deduct its costs to market. In particular, *CAPL 99* allows the lessee to deduct the following costs:

---

52 *CAPL 91*, *supra* note 43, s. 8.
53 *CAPL 99*, *supra* note 44, s. 6.
54 *CAPL 99*, *ibid.*; *CAPL 91*, *supra* note 52.
55 *Supra* note 43, s. 1(f).
56 *Supra* note 44, s. 1(h).

> [A]ny reasonable expense incurred by the Lessee (including a reasonable rate of return on investment) for water disposal and for separating, treating, processing, compressing and transporting Leased Substances beyond the wellhead, provided that the Royalty shall not be less than •% of the Royalty that would have been payable to the Lessor if no such expenses had been incurred by the Lessee.[57]

CAPL 91 provides that the lessee may

> deduct any reasonable expense incurred by the Lessee (including a reasonable rate of return on investment) for separating, treating, processing, compressing and transporting the leased substances to the point of sale beyond the wellhead or, if the leased substances are not sold by the Lessee in an arm's length transaction, to the first point where the leased substances are used by the Lessee for a purpose other than that described in subclause (b) hereof; provided further, however, that the royalty payable to the Lessor hereunder shall not be less than •percent (•%) of the royalty that would have been payable to the Lessor if no such expenses had been incurred by the Lessee. In no event shall the current market value be deemed to be in excess of the value actually received by the Lessee pursuant to a bona fide, arm's length sale or transaction.[58]

Under both CAPL leases all costs reasonably incurred by the lessee beyond the wellhead, to the point of sale, would be deductible. It is not clear that the potentially significant costs associated with the depressuring process would fall within the permitted deductions, as such costs would arguably be incurred in getting the product to the wellhead. Consequently, we recommend that *CAPL 91* and *CAPL 99* be revised specifically to contemplate the deduction by the lessee of costs incurred in depressuring.

This brings us, at last, to the question of to whom the royalty should be paid. In the event that the mineral rights to the natural gas and coal were held by separate parties and the lessee obtained leases from both, it will be necessary for the lessee to pay the royalty due under each lease. Failure to do so would jeopardize the mineral rights under one of the leases, thereby defeating the purpose of taking a lease from both mineral owners in the first place. Instead of negotiating a royalty based on a conventional gas well, it is recommended that the lessee point out to the lessor of each of the coal and natural gas rights that, in light of the uncertainty surrounding the ownership of rights to the CBM, the lessee is only in a position to offer a discounted royalty to both lessors, as opposed to the full rate to either of them. This would effectively shift the cost surrounding the ownership uncertainty from the lessee to the lessors.

F. SALT WATER DISPOSAL

As discussed in Part II, freehold ownership is ownership of an estate in fee simple, which is the largest possible bundle of rights that may be held. Conversely, certainly until the CAPL forms of leases came into use, a lessee under an oil and gas lease had one of the most insecure tenures known to common law. While it can be said that the positions of both the lessor and lessee have been shored up by the clarity brought to bear by the CAPL forms of leases, it appears that the underground disposal of salt water is not an activity contemplated by either form of lease.

---

57 *Ibid.*, s. 4(a).

58 *Supra* note 43, s. 4(a).

The granting clause, virtually identical for both *CAPL 91* and *CAPL 99*, reads as follows:

> Hereby leases and grants exclusively to the Lessee the Lands and all the Leased Substances ... together with the exclusive right and privilege to explore for, drill for, operate, produce, win, take, remove, store, treat and dispose of the Leased Substances and the right to inject substances into the Lands for the purpose of obtaining, maintaining or increasing production of the Leased Substances from the Lands, the Pooled Lands or the Unitized Lands and to store and recover any substances injected into the Lands.[59]

Although the lessee is granted the right to dispose of leased substances, that term is defined in *CAPL 99* to mean:

> [A]ll petroleum, natural gas and all other hydrocarbons ... and all materials and substances ... whether liquid, solid or gaseous and whether hydrocarbons or not, produced in association with petroleum, natural gas or other hydrocarbons or found in any water contained in any reservoir but only to the extent that the foregoing are included in the Certificate of Title.[60]

The *CAPL 91* definition does not state that leased substances are restricted to what is covered by the Certificate of Title. Nonetheless, the granting clause, in conjunction with the definition of leased substances does not apparently contemplate the underground disposal of salt water and this activity is not otherwise addressed in either of the CAPL forms of lease. For these reasons, the lessee is probably not entitled to dispose of salt water, such right being included in the bundle of rights held by the fee simple mineral owner.

IV. JOINT DEVELOPMENT AGREEMENTS

A. INTRODUCTION

1. UNIQUENESS OF COALBED METHANE DEVELOPMENT FACILITATES PARTICIPATORY RELATIONSHIPS

While the foregoing discussion addresses the nature of the CBM ownership debate and issues associated with utilization of standard form freehold leases that do not accommodate or reflect the uniqueness of CBM development, the discussion within this Part examines issues applicable to CBM joint venture agreements,[61] extends that analysis to issues associated with utilization of conventional form operating agreements, and addresses whether or not such agreements and procedures (without modification) are adequately designed to accommodate the exploration and development of CBM. Despite interest by many companies in the pursuit of CBM development, plans for its commercial exploitation are in their infancy, with several Alberta CBM projects classified as "experimental" schemes.[62] As a result, there

---

59 *Supra* notes 43, 41.

60 *Supra* note 44, s. 1(g).

61 Meaning participation agreements, farmout agreements, joint operating agreements and other joint venture style agreements.

62 See Scott Simpson, "Canada's coal-bed methane industry slow off mark," *The Vancouver Sun* (1 May 2003) D10 and Alberta Energy, News Release, "Alberta examines the potential for coalbed methane development" (22 October 2002). See also, Alberta, Department of Energy, *The Potential for Coalbed Methane (CBM) Development in Alberta* (Calgary: Heath and Associates, 2002) [*Potential for Coalbed*

is little published authority on what practical and legal considerations must be addressed in any joint development of CBM. The matter has, however, received the benefit of considerable legal analysis from American legal practitioners and others and this body of work provides an illustrative framework from which to consider joint venture agreement issues in the Canadian CBM context.[63]

Some might suggest that since CBM production is really only gas production after all, and since the two methods of operations share many similarities, there's no need to bother with drafting separate operating or development agreements. Exploration and development of CBM can and does, however, differ from exploration and development of conventional gas, with resulting legal and practical considerations that should be addressed in a joint venture situation. The following discussion highlights some of those differences.

A large and contiguous land base is not only advantageous, but likely required in CBM joint ventures to exploit the development potential of CBM operations fully.[64] Publicly available technical data is limited, and much existing data is still subject to confidentiality obligations. This is contrary to the decades' long history and volume of publicly available information for conventional gas exploration, completion and production practices. Operations are undertaken in distinct phases, not all of which result in production. Single exploratory wells, or core holes, are drilled first to determine net coal thickness, natural gas content and permeability. If the geological results thereof warrant further capital expenditures, pilot wells located in distinct patterns surrounding such exploratory wells will be drilled for the purpose of further evaluating and testing the potential commerciality of the coal seam identified by the exploratory wells. If the further information gained through pilot wells warrants the costs of drilling and completion of the next phase of development wells the construction of related compression and transportation infrastructure, multiple development wells will likely be undertaken. Depending on the results of those development wells, further development wells may be drilled and completed. Elections to undertake each phase of operations will be required within some finite measurable time, such as completion of the prior phase of operations or completion of a distinct operation, such as the date the last well required to be drilled in the prior phase was spud. What is meant by completion of such phase or distinct operation will have to be clearly addressed to establish an unequivocal triggering event for the ensuing election, as the consequences for failing to proceed may, at

Methane].

63 For examples of such articles, see the following: Kurt M. Petersen, "Coalbed Gas Development in the Western United States: Legal Issues and Operational Concerns" (1991) 37 Rocky Mt. Min. L. Inst. 13-1; Danielson, *supra* note 51; Marla J. Williams, "Coalbed Methane Joint Operating Agreements" in *Coalbed Gas Development* (Denver: Rocky Mountain Mineral Law Foundation, 1992) 12-1; Marla J. Williams, "Coalbed Methane Joint Operating Agreements" in *The Third Annual Coalbed Methane Special Institute* (Morgantown, West Virginia: Eastern Mineral Law Foundation, 1990) 5-1; Patricia Dunmire Bragg, "Purchase and Sale Agreements for Coalbed Methane Properties," in *Coalbed Gas Development* (Denver: Rocky Mountain Mineral Law Foundation, 1992) 13-1; and Carleton L. Ekberg, "Joint Participation Agreements for Coalbed Methane" in *Regulation and Development of Coalbed Methane* (Denver: Rocky Mountain Mineral Law Foundation, 2002) 2-1 at 2-8.

64 Some CBM operators have advised the authors that they believe a minimum of nine sections, but preferably a township of contiguous land is required to pursue CBM exploration properly and to pilot operations into commercial development.

a minimum, involve forfeiture of any right to future development operations on lands subject to such election.

CBM production does not occur until after the coal seam is depressured sufficiently so that the CBM may escape. This non-productive phase has taken more than a year in the Powder River Basin of Wyoming, although such experience has not been borne out by Western Canadian CBM projects to date.[65] Water produced during this phase is governed by a number of statutory and regulatory authorities, and must be either reinjected, disposed of or discharged at surface to evaporative ponds, rivers, streams or lakes in accordance with such statutes and regulations.[66] A greater number of CBM wells is required to be drilled than in conventional gas plays in order to achieve a reasonable expectation of commercial recovery, as production from individual CBM wells is generally lower than production from individual conventional gas wells.

Testing of CBM wells also differs from testing of conventional gas wells. Desorption analysis is required and results in a longer evaluative stage than is the case with conventional gas wells.[67] If wells are shut-in, those that are capable of production of CBM at the time of shut-in may not be capable of production at the time they are brought back on stream because further depressuring may be required to restore production. As a result, shut-in CBM wells may not serve to extend the primary term of standard form freehold leases if what is contemplated by "capable of production" in any quantity is not modified to allow for depressuring operations. Access to, or construction of, low pressure gathering systems is also usually required to collect the CBM for delivery to compressor stations. Increased compression is then required to deliver the low-pressure gas to often higher-pressure transportation systems. All of these elements contribute to increasing costs and delaying the commencement of sustainable commercial production, furthering the distinctions between CBM operations and conventional gas operations.

A number of non-operational factors also distinguish CBM development from conventional gas development. In instances where title to the CBM is unclear and there are competing coal and CBM development initiatives, a plethora of variables and opportunities for conflict arise, not the least of which is who should be a party to the agreement being contemplated. Where owners of the CBM rights do not also own the rights to mine the targeted coal seam, the CBM owners should consider whether or not to include the coal owners as a party to any joint operating agreement, or enter into some other form of joint

---

65 In some areas, CBM pilot projects are producing from "dry coals," with little or no associated water, and are handled as conventional gas wells. As a result, the depressuring phase in western Canada may not prove to be as long as in the western United States. See Danielson, *supra* note 51 at 8-4. See also, Canadian Association of Petroleum Producers, Media Advisory, "Coalbed Methane — Media Advisory" (11 March 2003) and background document, Canadian Association of Petroleum Producers (CAPP), "Responsible coalbed methane development in Canada" (March 2003), online: CAPP <www.capp.ca/raw.asp?NOSTAT=YES&dt =NTV&e=PDF&dn=43561>.

66 See Part V of this article for a further discussion on environmental issues associated with CBM exploration.

67 These tests involve the placement of the core taken from a CBM well into a special canister to measure the rate at which the gas is desorbed or released from the coal. Given that one element of such measurement is time, if the gas desorbs at a fairly slow rate, it may take a number of months before analysis of a particular core can be completed.

development agreement, and thereby provide for the orderly and uncontentious development of each party's mineral rights. This approach preserves privity of contract between the CBM owners and the coal owners and removes the risk that legal challenges may be brought to defeat the CBM owner's entitlement to win, take and remove CBM.

Given that companies may possess relatively little direct CBM evaluation expertise at the outset of a joint venture and little publicly available data exists upon which to make comparisons, parties can and should contemplate early on: what types of information they will be required to be shared; how it will be shared, interpreted and evaluated; and how decisions concerning how to proceed on the basis of such information will need to be made. Where transparency of information, technology transfer and sharing of best practices are common objectives of the parties, it may be beneficial to adopt a technical and/or operating committee approach to planning, budgeting, information assessment, interpretation and evaluation of available options. This approach establishes a methodology and timeline for attending to the numerous technical and operating decisions required to be made. If technical expertise, knowledge of the geology of coal seams and knowledge of CBM extraction techniques does not reside equally within participating companies, sufficient time must also be afforded to parties prior to making critical decisions for which significant consequences may attach. In addition, the impact on surface rights created by water disposal issues, the infrastructure required for roads, additional gathering systems, compression facilities and the potential for heightened activity levels and noise emissions requires a coordinated and consultative effort of all stakeholders in order to ensure that development occurs in a way that leads to compatible co-existence with surface landowners.

Participants in the development of an unproven resource are faced with the foregoing operational and non-operational challenges that raise uncertainties and increased risks. These combine to drive parties to seek participatory relationships to spread the risks, costs and benefits to be gained from CBM exploration and development.

2. APPLICATION OF CONVENTIONAL OPERATING AND FARMOUT AGREEMENTS

Conventional operating and farmout agreements have been developed through a process of industry-wide involvement, utilization and acceptance and they continue to evolve in reflection of the wisdom gained from the circumstances where they have been developed, tested and adapted. In this context, such agreements have compelling value for CBM operations and embody concepts and principles that can be adapted to reflect the nuances of CBM operations. Joint participants in CBM development would, however, be well-advised to consider what modifications need to be made to any standard form procedure intended for adoption, before entering into any farmout, exploration, development, participation, joint operating or other form of joint venture agreement, since the assumptions on which the standard form documents are based may not readily apply to CBM operations. Section C of Part IV of this article addresses these issues in further detail, and discusses some of the potential modifications that may need to be made, including various issues that have been addressed by CBM developers in their joint participation agreements.[68]

B. CONSIDERATIONS APPLICABLE TO COALBED METHANE PARTICIPATION AGREEMENTS

Assuming, for the purposes of this discussion, that parties have settled the foregoing ownership issues and satisfied themselves that leases granting rights to CBM are in place and are either still within their primary term or have been or are capable of continuance beyond the primary term (including through depressuring operations or testing/analysis operations), parties still have a number of contractual issues to address before proceeding with CBM development.[69] Parties will need to determine who should be a participant and the nature of their participation. Do all parties with mineral rights, including coal mining rights in a particular geographic area, wish to share in the risks and information to be gained by jointly developing the CBM potential? What minimum drilling obligations or blocks of land must be tested by the farmee in order to earn? What elections are applicable to each phase of operations, when must they be made and what consequences flow from failure to make such elections in accordance with the terms of the agreement? In what rights does the farmee earn its interest: CBM derived solely from the coal seam tested by a well; all natural gas within or to the base of a certain formation; or all petroleum and natural gas owned by the farmor to the base of depth drilled? In contrast to single well farmouts, where earning usually relates to the spacing unit of the test well and the balance of the section in which the test well is located, parties to a CBM farmout agreement will have to consider the minimum drilling and other obligations to be performed, the timing for performance of such obligations and whether earning occurs upon completion of each phase of operations, upon completion of some subset of such phase, on a well-by-well basis, or not until all obligations, once elected, have been fully performed. The coal seam or zones of interest in which earning occurs, as well as the timing of earning, will have to be clearly specified in order to avoid disputes.

Given that multiple wells may be required and drilled for different purposes during different phases of operations within the same block of lands and further used to trigger obligations or restrict rights with respect to such lands, a number of conceptual terms will require redrafting. For example, consideration will have to be given to how "commercial quantities" and "paying quantities" will be defined and how "drilling costs" and "operating costs" will be calculated. What costs are included in "payout"? What constitutes a "development well" and how does it differ from an "exploratory well" and a "pilot well"? When, if at all, should independent operations be allowed? What consequences flow from non-participation in such operations? Does the deal extend to construction and joint ownership of water disposal facilities and related compression and gas transportation facilities, or is the operator required to obtain access to such facilities from third parties with

68 Since confidentiality of such agreements is still a current obligation of parties to such agreements, the authors will not refer to the parties to such agreements or the express terms of such agreements, but will refer generally to concepts and principles that have been considered by the writer when drafting such agreements and U.S. legal authorities who have written on the matter.

69 The issues considered in this article are those issues that are unique to CBM development joint ventures and the authors do not purport to address all practical or legal considerations that parties must address when entering into such joint venture arrangements.

available, compatible capacity? What if the farmor is the party with such capacity — does the deal require some conveyance by the farmor of an entitlement to available capacity upon earning? If insufficient capacity exists within a compatible gas-gathering, compression and processing infrastructure, or access thereto is constrained due to lack of firm transportation or unacceptable pricing considerations, parties will have to determine whether they intend to construct such facilities under the joint participation agreement, to form a separate legal entity owned by them to build and operate the facilities, and whether or not the decision to participate in the costs of construction is mandatory at some approval threshold or optional, and if so, with what consequences. Will the party who operates the wells also be required to operate the facilities and, if so, on what conditions can operatorship be challenged?

The terms of a farmout, participation, joint venture or joint operating agreement will all be impacted by the decisions taken in respect of these various issues and by the degree of options that exist for parties at each stage of the decision-making process. If too many separate elections to participate are offered, the parties may end up with inordinately complex ownership, accounting and allocation issues that may make administering such an agreement extremely time-consuming and difficult.

I. NATURE OF SUBSTANCE SUBJECT TO JOINT PARTICIPATION

Early on in negotiations of any CBM transaction, the parties will have to determine whether their transaction is limited to exploration, development and production of CBM, or whether it extends to production of conventional gas from adjacent formations and interbedded sandstones or tight shales from which there may have been CBM migration. Critical to this issue will be how the parties chose to define CBM. No standard form definition appears to have achieved wide-spread acceptance in Canadian transactions, although most definitions the authors have seen attempt to define CBM in the context of the source in which it is found or derived from, such as "all gas found in, derived from or associated with coal beds, coal deposits, and coal seams."[70] In the Powder River Basin, joint participants in CBM projects have generally defined CBM as "gas, including without limitation, methane, ethane, propane, coal gas, coalbed gas, coal seam gas, fire damp and all other forms of gas produced from coal seams, coal beds or carbonaceous shales,"[71] implying the entitlement is one which first requires a party to reduce the CBM into possession. Consideration should also be given to whether the joint venture arrangement extends to a particular formation known or believed to be a coal seam, or whether it extends to any uphole or downhole petroleum and natural gas rights that may be discovered, or any potable water that is produced.[72]

If the CBM joint venture is developed within the context of a development agreement or other arrangement with the coal rights owner, where the coal owner has agreed to allow CBM

---

70 Represents a composite of definitions seen in private agreements.

71 Ekberg, *supra* note 63 at n. 30; and in particular see *supra* note 29 and accompanying text.

72 Produced water is owned by Her Majesty the Queen, in Right of the Province of Alberta, pursuant to the *Water Act*, R.S.A. 2000, c. W-3, but there is no express royalty regime in place to address potential revenues to be derived therefrom or whether the Crown will authorize the lessee to market it on the Crown's behalf, preserving for the CBM developer some potential to negotiate an additional revenue stream.

owners to capture and sell CBM related to the coal owner's mining activities, parties may have to consider whether their transaction extends to "gob gas" that accumulates within a fractured zone, resulting from the collapse of the roof of a coal seam due to underground mining and, if so, whether their definition of CBM is broad enough to capture such trapped methane.

2. EXTENT OF INTERESTS AND LANDS SUBJECT TO AGREEMENT

The amount of lands governed by the form of participation agreement chosen will, to a large degree, impact upon the nature of the obligations to be undertaken by both the farmor and the farmee. In large area farmouts, for example, where significant blocks of land or reserves (that is, townships) are dedicated or committed by the farmor to the farmee for CBM development and such development is required to occur over a number of years, rather than creating obligations upon the farmor to sterilize those interests until the farmee decides whether or not to pursue any CBM operations in respect of such lands, consider enabling the farmor to sell, assign and otherwise deal with or dispose of its interest in lands for which no CBM activity has then been proposed or undertaken. Such an enablement can be free and clear of any encumbrances created by the joint venture or obligations to the farmee. Once such lands have become the subject of proposed exploration operations, however, it would be inequitable to allow the farmor to sell such lands without giving the farmee a right of first refusal (ROFR) thereon. Consideration should therefore be given to what assignment provisions should prevail under the circumstances and take into account any conflicts that may arise regarding competing ROFRs created pursuant to existing joint operating agreements, especially where all parties with a claim to the CBM rights are not parties to the particular participation agreement contemplated and uncertainty remains with respect to the ownership thereof.

If the joint venture agreement does not encompass all working interest owners in a particular block of lands and the farmee wishes to pursue CBM operations in respect of the farmor's interest in such lands, consideration should be given to whether the farmor is required to dedicate its interest in lands where it holds less than 100 percent working interest, and if so, whether the farmor is required, or may elect at its option, to seek the consent or participation of its working interest partners through service of a notice of independent operations under the joint operating agreement that governs conventional gas operations in respect of the same lands. If there is an obligation, consideration will have to be given to the consequences for failure to obtain such consent or agreement to participate.[71]

3. AREA OF MUTUAL INTEREST

The obligations arising out of an area of mutual interest (AMI), where one party who acquires an interest in certain prescribed adjacent lands is required to offer the other party a right to participate on the same terms and conditions, admittedly creates administrative

[71] For example, will the lands governed by that proposal simply be removed from the deal or will parties preserve the right to resubmit that proposal upon changed circumstances, such as an assignment by a previously non-approving working interest owner to an assignee who favours CBM development or a non-approving working interest owner becoming an approving working interest owner after better understanding the risks and rewards associated with CBM development?

burdens and potential economic disincentives to parties. In CBM transactions, however, it is appropriate to include AMIs, given the nature of CBM development and the requirement for a contiguous land base. The conventional one to two year term may not be very meaningful, however, as the obligations under the AMI may expire before the depressuring phase has ended and desorption analyses are completed. Another factor that will have to be considered is how parties expect to participate in and consult with each other when bidding on Crown sales that post the disposition of petroleum and natural gas rights in addition to CBM rights, especially if such parties are competing with each other in conventional oil and gas operations in the same area. Consideration should also be given to the consequences arising on an election not to participate. Will the AMI in respect of that well or block of lands terminate or be preserved? In either case, parties should address whether such termination or preservation of the AMI applies to both parties or, if it terminates, whether it does so only in respect of the party who elected to participate so that the non-participating party is still obliged to offer the party who elected to participate a right to participate in future acquisitions made by the non-participating party.

4. WELL LOCATIONS

If the farmor or joint venture participants have conventional gas operations in the area that the farmee has targeted for CBM development, such parties may want the right to approve all well locations before applications for licenses are made in order to preclude CBM development from occurring on certain lands that might reasonably interfere with such parties' existing or potential conventional exploration operations. If granted, this right to make lands unavailable needs to be considered within the context of the farmee's minimum obligations, if any, so as not to place the farmee in a situation where it cannot perform.

If a well producing from another formation already exists in the spacing unit for the proposed CBM well and such lands are not excluded, the parties may also want or require, as a result of any existing surface leases or other surface use agreements, to utilize the existing well pad for such a CBM well.

5. CONTRACT/TARGET DEPTH

As with conventional farmouts, the parties must determine the formation to be tested by a CBM well and whether there is a requirement to drill any distance beyond the base of such formation to ensure that it is adequately tested. If separate coal seams exist and are viewed as separate sources of supply, it would be particularly important to define clearly the target depth. This would require the farmee to identify its targeted coal seam in advance of drilling, to avoid subsequent disputes over depth of earning. If the adjacent formation is an interbedded sand, the parties will have to determine whether the farmee earns in the overhole. Farmors with conventional gas rights which have not been contributed to the joint venture may still desire that certain zones above the targeted coal seam be perforated and tested during the drilling stage of a CBM well and, if so, parties should consider apportioning responsibility for the cost and performance of such operations, the risk of potential damage caused by such operations to CBM operations, and the resulting liability for same.

6. EXPLORATION OR CORE HOLE PHASE

In this first stage of a CBM project, all parties may simply wish to have one or more exploratory wells drilled within certain targeted areas to extract cores from prospective coalbeds and undertake analysis with respect to coal thickness, CBM saturation, permeability and hydrology to determine the prospects for electing to continue to the next phase. In the United States CBM context, these wells are known as "core holes" and are often not drilled for the primary purpose of completion as a CBM well.[74] All parties (including farmor and farmee, where applicable) should agree upon the location and required depth for such wells to maximize their geographical disbursement and to ascertain the areal extent of the coal seams and their respective potential geological and hydrological variations. While conventional farmouts usually provide for earning to occur upon drilling and completion or abandonment of a well, CBM farmouts and participation agreements may restrict earning to a later point in time and simply require the farmee to elect whether or not to proceed to the next phase of pilot operations once it has drilled the required number of exploratory wells to the required depth in accordance with the terms of the agreement. Failure to drill the minimum number of exploratory wells stipulated should result in termination of the agreement, with the only obligations that survive termination being the obligations so expressly stipulated in the agreement.

7. PILOT PHASE

This second phase of CBM operations typically follows the exploration or core hole phase and contemplates the drilling of up to four additional pilot wells where the farmee/operator has elected to proceed in respect of an exploratory well in order to determine the productive characteristics of the coal seams, evidenced by the core sample extracted from the exploratory well. Such wells are usually grouped into a specified number of wells in a defined pattern of contiguous spacing units, which design is intended to promote the depressuring of the targeted coal seam.[75] A specified period of time should be stipulated for drilling and either completion or abandonment of the required pilot wells and the operator's analysis of the results thereof.[76] If the farmee/operator proceeds with its pilot phase obligations in accordance with the terms of the agreement, it is generally allowed to elect to proceed with the development phase of operations. Earning may or may not occur at this stage, depending on what the parties have determined and in some American CBM deals, "[b]y drilling the pilot wells or pilot projects required by the exploration agreement, the operator will also earn a portion of the owner's oil and gas rights in the designated units upon which the pilot wells are drilled" and "may also provide for the operator to earn interests in adjoining or cornering units which may have been partially dewatered by the pilot wells."[77] Failure to perform the specified pilot operations will usually result in termination of the agreement, at least with respect to the block of lands identified as the area upon which future

---

74 Ekberg, *supra* note 63 at 2-17.

75 *Ibid.* at 2-18.

76 Such time frame may be triggered off the spud date of the exploratory well or some other easily ascertainable date.

77 Ekberg, *supra* note 63 at 2-19.

development operations could be undertaken.[78] The parties should provide for how decisions will be made in respect of budgets and proposed pilot operations and whether pilot wells will be required to be drilled to the same depth as the exploratory wells or to different depths, for example. Parties should also provide for an express timeline in which pilot operations, once commenced, must be performed and at what point during the pilot phase an election to proceed with development operations is required. Consideration should be given to whether the farmor desires a right to elect to participate in the pilot phase and, if so, whether it receives its participating interest share of the obligations (and any potential revenues) associated with the prior exploratory well or whether such obligations and revenues stay with the farmee.

It is also open to the parties to determine whether an exploratory well that is drilled during the exploration phase and subsequently completed for the purposes of production can be treated as satisfying a pilot well obligation, or whether another well drilled solely for depressuring purposes or pressure-monitoring purposes may be treated as a pilot well.

8. DEVELOPMENT PHASE

Provided the farmee/operator has performed its obligations in respect of the exploration and pilot phases, it shall be entitled to elect to continue into a development phase of the particular CBM project identified at the commencement of the exploration phase. In this phase, considerably more information should be available to guide parties' decisions about where and how to proceed. The farmor/owner should have an express right to participate at the outset of the development phase, notwithstanding any earlier decision by the farmor not to proceed with pilot operations. Some of the more significant issues to be determined by the parties at this point include: the extent to which the farmor is entitled to participate; whether the farmor's election includes an option or obligation to participate in the ownership of future associated production infrastructure; and whether such election extends to a right to back in to participation in the pilot wells and exploratory wells, and if so, whether or not the farmor is subject to some multiple of costs associated therewith for not having assumed its share of the risk at the outset.

The development phase will typically contemplate multiple well drilling and completion or abandonment operations that will be performed during a specified time frame. Development wells could be targeted for drilling and completion in rolling stages of some lesser number than the overall development well obligation to take into account and be able to respond to issues and other considerations that may arise during the development phase, and either with or without elections by the farmor to participate at each stage. The technical and operating committees, if established, would be well-positioned to provide the necessary oversight, planning, budgeting and decision-making required to implement and respond to changing circumstances arising during such operations. Parties should also determine whether any development wells drilled during a particular stage in excess of what was required can be considered to satisfy development well obligations during a subsequent stage. As in the case of exploration and pilot phase operations, failure to perform the minimum

---

78 Failure to perform pilot operations may also result in forfeiture of any and all interests in prior exploratory wells drilled as well as in any equipment placed thereon.

development obligations should result in termination of the agreement, release of undeveloped acreage and potential forfeiture of earlier earned interests.

9. TIMING OF OBLIGATIONS

The timelines specified in each of the three phases must be clearly determinable. If such timelines are suspendable due to reasons of force majeure, parties should consider whether there are particular circumstances that warrant inclusion as events of force majeure, especially if forfeiture is the consequence for timelines not being met. Similarly, if certain operations are required to continue a lease beyond its primary term or to maintain it, careful consideration should be given to ensure that the joint venture agreement provides the same operations and timing for completion as are required by the lease. An unmodified CAPL or freehold lease is problematic in this sense, since it usually requires production of leased substances (which does not include water) in paying quantities in order for the lease to be continued. If the coal seam is still being depressured at the end of a primary term, the lease could be lost.

An alternative to a specified timeframe would be to designate a stage in the process of completion of a particular well that must be met by a certain time. An example of such a stage is the point at which a well has been drilled and the equipment necessary for commencement of depressuring activities has been completed.[79]

10. OVERRIDING ROYALTIES, DEDUCTIONS AND EARNING

In conventional farmouts, farmees typically pay 100 percent of the costs to drill and either to complete or abandon a test well agreed upon by the parties, to earn a specified percentage of the farmor's leasehold interest in the spacing unit for such test well. Such agreements may provide for further option wells with similar earning provisions. Prior to payout of the capital costs associated with drilling and completing or abandoning the test well, the farmor typically reserves unto itself a gross overriding royalty of some fixed or sliding scale percentage of the gross proceeds of sale from production of petroleum substances from the test well. Such royalty may or may not be convertible into a working interest following payout, depending upon what the parties have agreed. However, it may also be the case that the farmor becomes the owner of a percentage of its original working interest upon completion rather than upon the occurrence of payout.

The amount of the overriding royalty, deductions therefrom and the percentage of interest earned upon satisfaction of the earning obligations will require special consideration in the CBM context because the standard approach of paying 100 percent to earn 50 percent does not reflect the risk/reward scenario for CBM operations. Economic drivers for the farmee favour a sliding scale royalty increasing at certain increments of production because a fixed royalty does not take into account the likelihood that CBM wells may be low and even marginal producers on an individual basis, in which case such royalty could be the difference between a well being economic or uneconomic. The parties will need to consider whether the royalty is payable on a well-by-well basis or on the overall production from an agreed-to

[79] Ekberg, *supra* note 63 at 2-9.

block of CBM operations. If the joint venture extends to gas from sources other than coal seams, consideration should be given to whether a different royalty regime applies and, if so, how the stream of gas will be measured to account for the different royalty payment structure. The farmee will want deductions from the overriding royalty to extend to depressuring operations, coring, logging, testing, gathering, transportation, dehydration and compression costs, while the conflict for the farmor may be that it is not prepared to entertain any deductions if it believes it has already compromised by accepting a lower royalty rate.

If the farmor has retained a conversion right, the point in time at which conversion occurs must be defined, and the liability for, ownership in, and access to the then existing or to-be-constructed water disposal or gas gathering and compression infrastructure must be addressed. Resolution of such matters may impact upon the point at which conversion occurs. To the extent that conversion occurs after such systems are in place, consideration should be given to how liabilities will be apportioned among the parties for operation, depressuring and production of the well, including environmental liabilities between the parties for any preexisting damage. In addition, if water disposal and gas gathering systems have been constructed and compressors installed, the farmee may wish to retain complete ownership of such infrastructure, to have the costs related thereto recovered as part of the payout account, and to seek to charge a capacity utilization fee to the farmor. If the farmor's interest upon conversion does not extend to such facilities, the farmor will likely resist inclusion of such costs in the payout account. If payout is calculated on a well-by-well basis, and such infrastructure serves all wells within a particular block or pod, a fairly complicated and potentially inequitable ownership structure may result. In order to resolve some of this inequity, some operators have allocated costs of the common infrastructure *pro rata* among the wells in the pod or block.[80] Although such an approach does not reflect actual use, due to non-uniform water production and gas production from each well served by the infrastructure, it offers the advantage of consistency and simplicity. A further refinement of this approach would be to allocate such common costs on the basis of actual utilization, although this would require measurement, adjustment and account balancing and has implications for apportionment of abandonment costs. The actual percentage of working interest that an overriding royalty converts into, or the percentage of interest earned by the farmee upon payout, will be a negotiated item that may be driven in part by the other considerations, such as amount of land made available, number and nature of minimum well obligations, timing of such obligations and degree of agreed-upon deductions from the royalty.

11. PARTICIPATING INTERESTS

If, instead of an overriding royalty, the parties agree to participate directly, decisions will have to be made in respect of the rights for which participation is offered, when an election must be made and what consequences flow from a decision not to participate. Such consequences could include an outright forfeiture by the non-participating party of its mineral rights, wells and facilities interests take the form of a deemed farmout by the non-participating party of its interest subject to an overriding royalty that could, if agreed, be convertible upon payout of some multiple of capital costs or take the form of a forced

80 *Ibid.* at 2-12.

conveyance at a pre-determined methodology for calculating the sale price. Alternatively, consideration should be given to the extent, if at all, the non-participating farmor party should have the right to back in after it elected not to participate. If such a right is offered, the parties must determine at what multiple of costs, attributable to the operations governed by the election not to participate, whether such a party is entitled to back in and whether such obligation is payable in cash upon its determination to back in, or out of the proceeds of such a party's share of production from such operations.

12. RIGHT TO TAKE OVER A COALBED METHANE WELL

Another aspect of the farmor's participation that should be contemplated by the parties is whether the farmor has the right to take over a well upon an election by the farmee to abandon it or upon the farmee's determination that the well is not suitable for use in subsequent CBM operations. Agreements should address the parties' respective rights and obligations regarding access to existing infrastructure, the requirement (if any) to buy into the existing infrastructure and, if so, the applicable conditions respecting such acquisition, as well as the responsibility for abandonment and apportionment of liability for pre-existing environmental damage, if any.

C. USE OF CONVENTIONAL AGREEMENTS FOR AN UNCONVENTIONAL RESOURCE

As indicated earlier, this portion of the article examines some of the conventional concepts in the *1990 CAPL Operating Procedure*[81] that require consideration and modification when applied to CBM participation arrangements. Many of the issues arise because operations, obligations and rights in the *CAPL 90 Operating Procedure* are defined on a well-by-well basis, while CBM operations contemplate phases of different operations and drilling obligations for multiple wells performed over blocks of land much larger than a single well spacing unit. Some of those terms are discussed below.

1. COMMERCIAL QUANTITIES AND PETROLEUM SUBSTANCES

Section 101(g) of the *CAPL 90 Operating Procedure* defines "commercial quantities" as follows:

> "*commercial quantities*" means, with respect to a *well*, the anticipated output of petroleum *substances* from *that well* which would reasonably warrant drilling *another well* in the same area to the formation indicated to be *productive* by that well, having regard to anticipated drilling costs, completion costs, equipping costs and operating costs, the kind and quality of petroleum substances indicated, the anticipated availability of facilities for treating and processing such petroleum substances and the anticipated costs of such services, the anticipated availability of markets for such petroleum substances, the anticipated availability of transportation service the delivery of such production to market and the anticipated cost of such service, the royalties and other burdens payable for the joint account with respect thereto, the probable life of *the well* and the anticipated price to be received for the petroleum substances as and when sold.[82]

---

81 Canadian Association of Petroleum Landmen, 1990 [*CAPL 90 Operating Procedure*].

82 *Ibid.* [emphasis added].

"Petroleum substances" is defined in s. 101(y) of the *CAPL 90 Operating Procedure* as "petroleum, natural gas and every other mineral or substance, or any of them, in which an interest in or the right to explore for is granted or acquired under the title documents."[83] Title documents are unlikely to extend the right to ownership of water, since water is owned by the Crown.[84] The term "commercial quantities" is therefore unlikely to extend to water and actually is only used in the *CAPL 90 Operating Procedure* in the context of defining the level of production that a well must achieve or be capable of achieving in order to be classified as a "development well." Given the way CBM recovery is maximized through different phases of operations and the fact that some wells may be drilled to serve purposes other than recovery of petroleum substances, it would be unreasonable to require that the test of commercial production be restricted to the output of a single well. Because commercial production of CBM might not be achievable without the strategic placement of prior exploratory and pilot wells to depressure the coal seam, it would be important to capture the aggregate of all costs incurred in respect of all wells within a designated exploration or development block to determine whether or not commercial production had been obtained. Moreover, if any joint venture obligations are triggered or rights restricted by the presence or absence of "commercial production," the concept needs to consider fairly the nature of how development operations are performed in order to capture accurately the relevant costs associated with such development.

2. PAYING QUANTITIES

Use of the *CAPL 90 Opertaing Procedure*'s definition of "paying quantities" in the CBM context provides similar difficulties. Section 101(x) of the *CAPL 90 Operating Procedure* defines "paying quantities" in the context of the anticipated output from a single well of that quantity of petroleum substances that would reasonably warrant incurring the same costs as stipulated in the definition of "commercial quantities" with the exception of drilling costs.[85]

While "commercial quantities" was used to qualify whether or not a well was a development well, the term "paying quantities" in the *CAPL 90 Operating Procedure* triggers certain obligations and restricts certain rights. For example, if less than all parties elect to set production casing and complete the well for the taking of petroleum substances in "paying quantities," participants must elect, pursuant to clause 903 of the *CAPL 90 Operating Procedure*, whether or not the setting of such production casing is considered an independent operation or whether the non-participating parties must assign their interest in the zone for the spacing unit in which the well was completed to the parties that paid their share of such costs.[86] The prospect of fragmented ownership rights and independent elections may be palatable on a well-by-well basis, but it becomes unwieldy in an area when tens or hundreds of wells are to be drilled. In addition, given that the casing point election in the *CAPL 90 Operating Procedure* only applies to wells completed for the taking of petroleum substances in "paying quantities," query whether any party should be allowed to undertake independent operations in the context of wells not drilled for such purpose, such as exploratory wells or

83 *Ibid.*
84 See the discussion under Part V of this article and s. 3(1) of the *Water Act*, R.S.A. 2000, c. W-3.
85 *Supra* note 81.
86 *Ibid.*

disposal wells or the recompletion of a pilot well into an injection well. If an independent operation contemplates the drilling of a well and the well is not capable of production in paying quantities on the basis of the *CAPL 90 Operating Procedure* definition, clause 1006 of the *CAPL 90 Operating Procedure* requires the participating parties to abandon the well in a timely manner.[87] This does not work in the CBM context if, as suggested, an independent operation is performed to convert a well from a non-productive well to an injection well or a disposal well because of the intervening requirement for abandonment, which may not be in the best interests of overall development of the project.

The term "paying quantities" is also used in clause 1008(a) of the *CAPL 90 Operating Procedure*, which restricts independent operations for deepening, plugging back, whipstocking, recompleting or reworking operations with respect to wells producing or capable of production in paying quantities.[88] If such a well is only capable of production in paying quantities, but recompletion operations are desired or deemed required by less than all of the parties to prove its productive capabilities, clause 1008 would appear to restrict such action.

3. PAYOUT

The concept of payout is closely aligned to when a well or wells are capable of producing in paying quantities and whether the parties account for payout on a well-by-well basis or in terms of project costs or total exploration block costs. The *1993 CAPL Farmout & Royalty Procedure*[89] provides two alternatives for consideration, the first of which is tied to the date the farmee recovers all drilling, capping, completion, equipping and operating costs, all overriding royalty payments, all taxes (other than income taxes) paid by the farmee, all encumbrances applicable to the well, and all facility fees (as those terms are specifically defined in the *CAPL 90 Operating Procedure*), out of the farmee's share of production of petroleum substances from the particular well. The second alternative for payout is the earlier of the date upon which 100 percent of production from or allocated to such well (before all royalties and encumbrances) is some measure of cubic metres of production or some number of years following rig release for the well.

Given that CBM wells may be drilled for a purpose other than producing petroleum substances, by utilizing a payout definition that contemplates costs related to a particular well, it is likely that payout will never occur in respect of some wells, allowing the farmor or party with a conversion right to avoid participation in and obligations arising in connection with, wells which will not payout. In addition, given that operating costs under s. 101(t) of the *CAPL 90 Operating Procedure* refer to "moneys expended (exclusive of drilling costs, completion costs and equipping costs) to operate a well for the recovery of petroleum substances,"[90] it is not clear whether costs unique to CBM operations, such as desorption analysis and other forms of production testing, water handling and disposal costs are necessarily "monies expended to operate a well." In consequence, "payout" will need to be

87 *Ibid.*

88 *Ibid.*

89 Canadian Association of Petroleum Landmen, 1993.

90 *Supra* note 81.

broadly written to reflect the additional costs that may be incurred in connection with CBM operations.

Parties should also consider whether all potential revenues have been taken into account when calculating payout. If revenues are restricted to gross proceeds of sale from a party's share of production of petroleum substances, and potable water is produced (which although owned by the Crown, may in the future result in some fees being received by the operator if it disposes of such water on behalf of the Crown), or water disposal fees are generated through the conversion of a well into a disposal well, then payout may be artificially delayed.

4. DIFFERENCES BETWEEN EXPLORATORY WELLS, PILOT WELLS AND DEVELOPMENT WELLS

Reference has been made to the fact that CBM wells may be drilled for different purposes. Therefore, it is important to consider and define what obligations or considerations characterize an exploratory well, a pilot well and a development well. In addition, given that joint venture arrangements may require that earning in the lands is tied to a minimum set of obligations related to drilling and completion or abandonment of a certain number and type of wells within each category, consider defining such wells by their objective. Under s. 101(n) of the *CAPL 90 Operating Procedure*, an "exploratory well" is defined as a well, insofar as it is not a development well, meaning that any well, other than a well which is "stratigraphically above the base of the deepest geological zone in which an existing well within 3.2 kilometres thereof ... is or has been capable of production of petroleum substances in commercial quantities,"[91] will be an exploratory well. These concepts are problematic from a number of perspectives. CBM development wells may well be drilled above or below the deepest geological zone of the nearest well within 3.2 kilometres and be drilled within reduced spacing of less than 3.2 kilometres from the next development well. In addition, given that different penalties apply in the *CAPL 90 Operating Procedure* to non-participation of exploratory wells versus development wells, there is no distinction for obligations triggered or rights restricted as a result of failure to participate in pilot wells. Consider therefore defining an exploratory well as a well drilled to determine net coal thickness, natural gas content and permeability. Such wells may not even be cased in order to evaluate the CBM potential associated with them. A pilot well, while not defined in the *CAPL 90 Operating Procedure*, could be defined as part of a pilot project that is drilled and cased to test and evaluate the commerciality of CBM production. A development well could be defined as part of a defined development project or phase that is drilled, cased and either completed or abandoned to validate the economic producibility of CBM.

5. INDEPENDENT OPERATIONS

The nature of the classification of a well also has implications with respect to a party's obligations and rights under the independent operations provisions of art. 10 of the *CAPL 90 Operating Procedure*. A party that is proposing independent operations must classify the operation pursuant to clause 1002(a)(iv) as a development well or exploratory well, and must

---

[91] See also the definition of development well at s. 101(j) of the *CAPL 90 Operating Procedure*, *ibid.*, where this restriction applies.

also state whether or not that well is a title-preserving well.[92] Clause 1005 further complicates the matter by providing for independent operations and split ownership within a single well which could in part be both a development well and an exploratory well.[93] Given the multiplicity of wells that could be drilled within a block targeted by a farmee or joint venture participant for CBM exploration and development, obvious administrative, accounting and operating issues arise as a result of any blanket adoption of such a provision. Careful consideration should be given as to when, and what kind of, independent operations could be proposed and whether they should be restricted, if at all, to after a development phase or operations have been instituted in connection with a particular pilot phase. Careful consideration should also be given to the consequences for non-participation in the event that independent operations can even be proposed. To avoid the overall operating, accounting and potential assignment issues that would arise from permitting independent operations to be performed prior to completion of minimum well obligations, consider whether acreage forfeiture of an entire exploration block, pilot area or development area should be contemplated to incent participation, or whether the non-participating party should be subject to penalty of a higher recovery of the costs of such operations, or even whether such party should be required to assign, convey or farm-out its non-participating interest in exchange for some nominal consideration.

6. PRODUCTION FACILITIES

If the joint venture arrangement is to extend to construction of production facilities, consider whether the *CAPL 90 Operating Procedure* definition is sufficient. As written, the definition at s. 101(z) extends to "any facility serving (or intended to serve) more than one (1) well (including ... any battery, separator, compressor station, gas processing plant, gathering system, pipeline, production storage facility or warehouse)."[94] Noticeably absent from this list are the water disposal facilities that will be required in order to dispose of the water and achieve commercial production of CBM. Consider whether the construction of such facilities should be required to be developed jointly by the parties and not subject to any potential notice of independent operation, as such facility may be used to serve a number of different phases of operations, both within a single exploration block and multiple exploration blocks. One of the consequences of clause 1021 of the *CAPL 90 Operating Procedure* is that "failure of a party to make an election with respect to such operation notice ... shall be deemed to be an election by such party not to participate in such operation."[95] If the definition of production facility was to include water disposal facilities, but this clause was not modified accordingly, a party could be stuck with the operation and accounting logistics associated with disposing of its share of produced water. As a result, careful consideration should be given to whether independent operations should even apply prior to completion of the various phases of operations and even then, as to what consequences should flow from non-participation. In order to avoid the operational and accounting issues arising from such non-participation, consider forfeiture, a flow-through of associated

---

92 *Ibid.*
93 *Ibid.*
94 *Ibid.*
95 *Ibid.*

operating costs with some penalty, or an additional handling charge to the party who elects not to participate.

As the foregoing discussions suggest, CBM development is proving to be a unique and challenging resource, not only in terms of its potential operational issues, but also in terms of the myriad of legal, developmental, operational and practical issues that must be addressed in any agreement that grants a leasehold interest therein or a right to participate in the extraction, development and production thereof.

V. ENVIRONMENTAL MATTERS

CBM development introduces several unique environmental challenges in addition to those related to conventional oil and gas development.[96] Environmental concerns related to CBM development principally centre around water. For instance, if great quantities of water were to be removed during the depressuring phase, and from depths equivalent to fresh water aquifers, it could have the potential to lower groundwater aquifers significantly, causing nearby landowners to abandon existing water wells and drill deeper ones. Surface discharge of produced water can cause land and water contamination and increase soil salinity, depending on water quality. These issues are in addition to the various environmental concerns faced by operators pursuing conventional development, such as surface disturbance and noise pollution.

A. WATER TREATMENT AND DISPOSAL

CBM development has been portrayed as really an exercise in water management.[97] A CBM well starts as a water well and becomes a gas well after some volume of water is removed from the coal seam. This depressurizes the coal beds and allows natural gas to flow. The quantity and variable quality of water produced during CBM development makes water treatment and disposal the primary environmental challenge to CBM development.

1. ALBERTA

In Alberta, there is some overlap of jurisdiction between the AEUB and the DOE for water treatment and disposal matters related to CBM development. The AEUB is granted jurisdiction, under the *Oil and Gas Conservation Act*, over the gathering, storing and disposal of water produced in conjunction with oil or gas.[98] Under the *Environmental Protection and Enhancement Act*,[99] the DOE has broad jurisdiction over the environment, including the regulation of the water quality of discharged water in the province. In addition, Alberta Environment requires an impact assessment of CBM projects before it will issue an approval for dewatering fresh or non-saline aquifers.

---

96 This discussion on environmental issues draws heavily on a paper prepared by Alan Harvie (of Macleod Dixon), "Legal and Regulatory Aspects of Coalbed Methane Development" (Paper presented at the Annual Unconventional Gas & Coalbed Methane Conference, October 2002) [unpublished].

97 Ernie Hui, "Issues Relating to Water Disposal — The Alberta Perspective" (Paper presented at the Conference Board of Canada's Conference on Understanding the Business of Coalbed Methane, February 2003) [unpublished].

98 *Supra* note 22, s. 39.

99 R.S.A. 2000, c. E-12.

Generally, the *Oil and Gas Conservation Act* requires that the AEUB approve any scheme for the gathering, storage and disposal of water produced with oil and gas. Prior to approval by the AEUB, it must refer the application to the DOE for its approval as to environmental matters. The DOE may give approval with or without conditions.[100]

Also, a licence from the DOE for the diversion of groundwater will be required to the extent that the produced water is not saline. The *Water (Ministerial) Regulation*[101] provides that no licence is required for the diversion of saline groundwater, that is, "water that has total dissolved solids exceeding 4000 milligrams per litre."[102] This is an exception to the general requirement under s. 49 of the *Water Act*[103] for a licence for the diversion of groundwater. Where approval is required under the *Water Act*, approval following an environmental assessment under Part 2 of the *Environmental Protection and Enhancement Act* is also required.[104]

There are a number of options for disposing of the quantity of water produced during CBM production, including surface discharge to evaporation ponds or watershed (rivers, lakes, *etc.*), deep well injection or injection to groundwater aquifers, and commercialization.[105] Often, treatment of the produced water will be necessary prior to disposal through these methods.

Surface discharge of produced water in Alberta requires approval from the DOE under the *Environmental Protection and Enhancement Act.* Also, water for surface disposal must comply with the *Surface Water Quality Guidelines in Alberta,*[106] which set water quality-based approval limits for water discharges.

Deep well disposal in Alberta is governed by the *Oil and Gas Conservation Act*[107] and *Guide 51: Injection and Disposal Wells — Well Classifications, Completion, Logging, and Testing Requirements.*[108] Generally, as indicated in *Guide 51*, "[d]eepwell disposal of oilfield and industrial waste waters in Alberta is a safe and viable disposal option where wells are properly constructed, operated, and monitored."[109] The location and purpose of a disposal well must first be approved by the AEUB as part of a specific scheme under the *Oil and Gas Conservation Act* and *Oil and Gas Conservation Regulations.*[110] Each injection or disposal well must be classified into one of four groups indicating the appropriate level of monitoring and surveillance required for such a well based on the type of fluids being injected.[111] *Guide*

---

100 *Supra* note 22.
101 Alta. Reg. 205/1998.
102 *Ibid.*, s. 1(1)(z).
103 R.S.A. 2000, c. W-3.
104 *Supra* note 99, s. 9(1) of Schedule of Activities.
105 *Potential for Coalbed Methane*, *supra* note 62.
106 Alberta Environment, Environmental Assurance Division and Science and Standards Branch, *Surface Water Quality Guidelines in Alberta* (Edmonton: Alberta Environment, 1999).
107 *Supra* note 22, s. 37.
108 Alberta Energy and Utilities Board (AEUB), *Guide 51: Injection and Disposal Wells — Well Classification, Completion, Logging, and Testing Requirements* (Calgary: AEUB, 1994) [*Guide 51*].
109 *Ibid.* at 5.
110 Alta. Reg. 151/1971.
111 *Supra* note 108 at 7.

51 contains additional operating and monitoring procedures to be followed, which are aimed at ensuring wellbore integrity during injection or disposal operations.[112]

Produced water from CBM development is only suitable for deepwell disposal in Alberta if it falls within a specified range of pH levels and contains concentrations of certain chemicals and compounds lower than specified levels. More importantly, deepwell disposal of the produced water is only permitted if such water does not meet surface water discharge criteria. Treatment and return to the surface or watershed of produced water is the preferred waste management option, as treatment technologies are standard and well established and water conservation principles are strongly applied.[113]

Commercial methods of water disposal, such as sale for irrigation, livestock and other domestic purposes, are generally unavailable in Alberta. Unless a CBM developer is specifically granted rights to produced water, it has no right to sell such water, as ownership is vested in the Crown.[114]

2. BRITISH COLUMBIA

In British Columbia, the Oil & Gas Commission (OGC) and the Ministry of Water, Land and Air Protection (MWLAP) have overlapping jurisdiction with respect to water treatment and disposal issues for CBM development. However, in contrast to the situation in Alberta, there is no general licencing or approval requirements for water disposal. Also, no licence is required for the diversion of water during CBM development; the *Water Act*[115] currently only requires a licence for the diversion of surface water. However, a CBM developer must comply with different legislative requirements, depending on whether it uses surface or subsurface disposal. For surface disposal of produced water, a permit or approval under the *Waste Management Act*[116] is required. Applications are made to the OGC that are then forwarded to the MWLAP for review and comment. The MWLAP reviews the application to ensure that the proposed water disposal complies with provincial legislative and regulatory requirements and makes recommendations to the OGC with respect to the application. The OGC has the power to grant the permit or approval subject to any conditions considered necessary for the protection of the environment, and will typically include conditions from the MWLAP recommendations.[117]

Also, prior to surface disposal, water must be tested and treated to ensure that it meets certain quality standards as set forth in the *Draft Standards for the Discharge of Produced Water from Coal Bed Methane Operations*.[118] As noted in the *Guidelines for Coalbed Methane Projects in British Columbia*,[119] the OGC and the Environmental Protection

---

112 *Ibid.*

113 *Ibid.* at 6.

114 See s. 3(1) of the *Water Act*, *supra* note 84, and s. 2(1) of the *Water Act*, R.S.B.C. 1996, c. 483.

115 R.S.B.C. 1996, c. 483.

116 R.S.B.C. 1996, c. 482, ss. 10 and 11.

117 British Columbia, Oil and Gas Commission, *Guidelines for Coalbed Methane Projects in British Columbia*, (Victoria: Oil and Gas Commission, 2002) [*Guidelines for Coalbed Methane*].

118 British Columbia, Oil and Gas Commission, *Draft Standards for the Discharge of Produced Water from Coal Bed Methane Operations* (8 July 2002) [*Standards*].

119 *Supra* note 117.

Division of the appropriate MWLAP regional office should be contacted early in the project planning process to assist with the interpretation of the *Standards*.[120]

As an alternative to surface disposal, a CBM developer in British Columbia may apply for approval to inject produced water into underground formations where the volume or quality of such water makes surface disposal inappropriate. Section 94 of the *Drilling and Production Regulation*[121] under the *Petroleum and Natural Gas Act*[122] requires that all water produced at a facility or well must be disposed of to an underground formation in accordance with a scheme approved by the OGC. Applications to the OGC must include all items listed in the *Guideline for Approval to Dispose of Produced Water*,[123] including detailed information with respect to the well and written statements from third parties who may be affected by the proposed water disposal scheme. Notice of the application is published in the *British Columbia Gazette* to give other affected parties the right to raise any concerns with the proposed scheme. The OGC will consider these concerns and the application and may issue its approval subject to any necessary conditions. A Monthly Injection/Disposal Statement setting forth the volumes of disposed water must be submitted to the OGC within 25 days of the end of each month where water is disposed of to an underground formation.

Commercial options for water disposal are similarly limited in British Columbia as in Alberta, since ownership of water resources is vested in the Crown.[124]

B. FLARING

Although flaring is an environmental issue for all oil and gas development, there may be additional concerns in the context of CBM development due to lower pressure and volumes of gas.

In Alberta, flaring is extensively regulated by the AEUB in accordance with *Guide 60 — Upstream Petroleum Industry Flaring Guide*.[125] In addition, the *Oil and Gas Conservation Regulations* require that a permit be obtained from the AEUB to flare gas containing 50 moles of H_2S per kilomole of gas or more, or to volumes exceeding 600 10^3m^3.[126]

In British Columbia, flaring oil or gas produced from a well or facility is prohibited under the *Drilling and Production Regulation*, except as required for drill stem testing or unless the OGC has given written permission.[127] All flaring must be conducted in the manner specified in s. 58(4). Application for permits must comply with the requirements set out in the *Interim Guideline #OGC 00-01 — Natural Gas Flaring During Well Testing*,[128] which

120 *Ibid.* at 13.

121 B.C. Reg. 362/98.

122 R.S.B.C. 1996, c. 361.

123 British Columbia, Oil and Gas Commission, *Guideline for Approval to Dispose of Produced Water* (June 2000).

124 *Supra* note 117.

125 Alberta Energy and Utilities Board (AEUB), *Guide 60 — Upstream Petroleum Industry Flaring Guide* (Calgary: AEUB, 1999).

126 *Supra* note 110, ss. 7.055, 11.135.

127 *Supra* note 120, s. 71(4).

128 British Columbia, Oil and Gas Commission, *Interim Guidleine #OGC00-01 — Natural Gas Flaring During Well Testing* (February 2000).

includes computer model evaluations for flaring of gas with H_2S concentrations of 5 percent or greater and a public consultation process.

C. GREENHOUSE GAS EMISSIONS CREDITS

CBM development involves the release of two greenhouse gases, methane and carbon dioxide. If such gases could be captured during development or emission levels of such gases lowered by the use of enhanced CBM production methods, a CBM developer in Canada may be able to capitalize on opportunities for trading greenhouse gas emission reduction credits in light of the *Kyoto Protocol to the United Nations Framework Convention on Climate Change*.[129] However, with the *Kyoto Protocol* still in policy form with little, if any, implementation and the market for greenhouse gas emission reduction credits still in its infancy in Canada, the true potential for such environmental opportunities to CBM developers at this time remains unknown.

VI. CONCLUSION

While the industry in Canada is relatively new, one should not lose sight of the fact that CBM is nothing more than natural gas from a coal seam. As such, there is an existing legal and regulatory framework within which its development can be regulated. This will ensure that production occurs in an environmentally responsible manner and that the Province of Alberta as a whole will benefit from the resulting long term growth, stability and profitability in the energy sector.

The DOE has struck a cross-ministry tenure sub-committee and a royalty sub-committee to assess whether changes to existing legislation or regulations are called for to facilitate CBM development. Consultation by these two sub-committees is underway and it is anticipated that they will produce reports by late fall of 2003. The Canadian Association of Petroleum Producers Natural Gas from Coal Task Group completed a report and made recommendations in May 2003. The Canadian Society for Unconventional Gas has various initiatives underway as well.

The purpose of this article was to highlight aspects of CBM development that call for changes to be made to leases and various forms of agreements typically used in the oil and gas industry and to offer alternative drafting solutions. By adapting agreements to contemplate CBM development, parties should be able to reduce the risk associated with a project, thereby enhancing its chances for success. The issues raised in this article represent a snapshot in time, however, and will undoubtedly change as projects make the transition from pilot to commercial, as the industry itself matures and as the legal and regulatory frameworks governing CBM continue to evolve.

---

[129] 11 December 1997, U.N. Doc. FCCC/CP/1997/L.7/Ad.1, 37 I.L.M. 32 (1998) [*Kyoto Protocol*].