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On Record Contents:

Operators' Liens
 Establishing Priority
Page 1

What We've
 Been Up To
Page 7

Royalty Owners' Liability
 For Share of Processing
 Costs Depends on
 Terms of Agreement
Page 3

Weyerhaeuser
 V. Hayes:
 Reconsidering The
 Law of Assignment
Page 8

Shortage of CO_{2e} Offsets
 Predicted under Federal
 Regulatory Scheme
Page 5

Update on Klemke
 Mining Corp. v.
 Shell Canada Ltd.
Page 9

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Operators' Liens: Establishing Priority

by Sarah Nossiter and Jeremy Barretto, Summer Research Student

Introduction

A recent unreported decision, *Bearspaw v. Brookfield* from a December 18, 2007 sitting of the Alberta Court of Queen's Bench, could impact the value and enforcement of operators' liens in the oil and gas industry.

Facts

Bearspaw Petroleum Ltd. ("Bearspaw") claimed an operators' lien against the well it operated for, among others, a now insolvent joint operator (the "Owner"). Bearspaw did not register its operators' lien under the Personal Property Security Act (the "PPSA")¹. In a contest with a secured lender (the "Lender") that had registered under the PPSA, Bearspaw sought to have its unregistered operators' liens declared in priority to the security of the Lender, in relation to the personal property associated with the well.

Bearspaw argued that operators create value in oil and gas operations that would not otherwise be realized. Thus it should equitably enjoy priority for recovery of costs from the Owner. Bearspaw claimed the "commercial reality" of the oil and gas business to protect its unregistered interest; filing of liens interferes with the operation of business and would lead to unreasonable delays.

Therefore, it claimed most oil and gas operators do not register liens under the PPSA.

Madam Justice Horner held that Bearspaw's unregistered interests rank after the registered interests of the Lender. The Court relied on *Direct Energy Marketing Ltd. v. Kalta Energy Corp*² to conclude that certain priority provisions of the PPSA, which on their face would seem to apply to liens similar to operator's liens, apply only to non-consensual liens. Bearspaw's lien, arising as it did from an operating agreement between the parties, was a consensual contract with the Owner, rather than an enforceable non-consensual lien.

Broader Issues

Subsequent to the *Bearspaw v. Brookfield* decision, there are broader questions regarding the enforceability of operators' liens in the oil and gas industry. The *Canadian Association of Petroleum Landmen (CAPL) Operating Procedure* is the instrument which typically gives rise to an operators' lien. There are several operators lien remedies listed in CAPL such as charging interest or exercising a form of set-off.

Going forward, what options do operators have to ensure their liens are enforceable?

The Bearspaw v. Brookfield decision raises concerns regarding the priority of operators' liens over other registered interests.



Options for Operators

Liens can be held against either real property or personal property. Liens as against personal property can be registered under the *Personal Property Registry* (PPR) in accordance with the PPSA.

1. Registration under the PPR

The Lender suggested operators should register their liens to ensure enforceability. Specifically, a financing statement can be registered under s. 43(4) of the PPSA before any other security interest arises.

A PPR registration is, while potentially ensuring priority as against personal property interests relating to a well, not likely an attractive solution for most operators. It could be administratively complex, particularly when dealing with multiple joint operators. At the outset Lenders might be willing to discuss permitted encumbrances as a business cost, rather than when an owner is facing insolvency. However, in many cases Lenders will likely refuse to advance in the face of an operators' lien, necessitating some form of postponement or priority agreement.

2. Registration against real property

Liens against real property can be registered under the *Law of Property Act*.³ *Bears paw* argued s. 64 of the *Law of Property Act* prohibits registration of liens against Crown Lands. Section 202 of the *Land Titles Act*⁴ also prevents the registration of liens against mines and minerals on Crown Lands. Therefore, registration against real property may not be an effective remedy for operators who work primarily on Crown Lands.

3. Registration under the Mines and Minerals Act

The *Mines and Minerals Act*⁵ allows for registration of a security notice against the interests of a lessee in an agreement. However s. 94 of the *Mines and Minerals Act* specifically excludes registration of an operators' lien.

4. Registration under the Builder's Lien Act

Liens may also be registered against real property as a builder's lien under the *Builders' Lien Act*.⁶ However, there are several logistical problems facing operators intending to register under the *Builders' Lien Act*. First a registered mortgage would still enjoy priority over a builder's lien under s. 11(4). Secondly, the remedy for a builders' lien could involve the sale of the entire property. The *Builders' Lien Act* also effectively imposes time limitations on pursuing claims once a lien is filed.

5. Words of priority

Specific Language in security agreements between a lender and an owner could give priority to an operator's lien. In *Chips Inc. v. Skyview Hotels Ltd.*⁷

the Court of Appeal clarified that clear "words of priority" are required to gain a priority interest in security agreements:

...any such mortgage, lien or other encumbrance shall rank in priority to the charge hereby created. *Euroclean Canada Inc. v. Forest Glade Investments Ltd.* (1985), 16 D.L.R. (4th) p. 289 (Ont. C.A)

Since they are not a party to security agreements between a lender and an owner, it could be challenging for an operator to gain specific language to protect its interests.

6. Payment options

Given the uncertainty regarding the enforceability of operators' liens, it is important operators do not allow joint operators to continue in arrears without taking prompt action. In addition to liens, operators could use cash calls or advance payments to help protect against a joint operator's insolvency. But this would require operators to issue cash call against non-defaulting joint operators.

7. Negotiation with the lender

It is assumed that in many situations the receiver or lender will want to keep the operator working in the event of a bankruptcy. There is generally no obligation for the operator to continue to provide services on credit. However, such arrangements would in most cases be on a go-forward basis and wouldn't address past debts. The lenders' attitude towards giving the operator preference for past debts would likely depend on the level of security they possess. It would be preferable for the operator to negotiate a priority agreement with the bank in advance.

Conclusion

The *Bears paw v. Brookfield* decision raises concerns regarding the priority of operators' liens over other registered interests. Negotiating a priority agreement with the lender in advance could prevent future problems resulting from a joint operator's insolvency. Registration of a lien against real or personal property where possible could strengthen an operator's interest, although this might not provide priority over a lender's interest. In any case, operators would be wise to carefully track payments to minimize their losses in the event of a joint operator's insolvency.

Footnotes

¹R.S.A. 2000, c. P-7

²[2002] A.J. No. 463 (Q.B.)

³R.S.A. 2000, c. L-7

⁴R.S.A. 2000, c. L-4

⁵R.S.A. 2000, c. M-17

⁶R.S.A. 2000, c. B-7

⁷[1994] A.J. No. 562 (C.A.)

Royalty Owners' Liability For Share of Processing Costs Depends on Terms of Agreement

by Steve Smyth, Student-at-Law

Introduction

It is common practice for royalty agreements to calculate royalty liability at the wellhead, thereby requiring a royalty owner to pay its share of the costs from that point forward to the point of sale. Such a relationship is often desirable and fair since processing costs will vary depending on the location of the first point of sale. Despite this customary practice, parties should be aware that there is no rule of law in Alberta obliging a royalty owner to pay for a share of processing costs unless such terms are stipulated in the royalty agreement¹. This issue was recently addressed by Mr. Justice Macleod of the Alberta Court of Queen's Bench in *574095 Alberta Ltd. v. Hamilton Brothers Exploration Company*², ("Hamilton").

Facts

Hamilton Brothers Exploration Company ("Hamilton Bros.") began operations in Alberta and British Columbia in the 1960's and 70's. Due to changes in Federal tax policies, Hamilton Bros. sold most of its properties to Carter Oil & Gas Limited ("Carter") for a purchase price of \$32 million, plus the payment to the vendor of a royalty it had reserved for itself. The bulk of the payment for the assets was structured as a royalty that was to terminate when total payment equalled \$490.5 million. In the 1980's Carter spun the working interest to ten companies (the "Tencos"). The issue first arose in 1995 as to whether the royalty owners should be liable for a share of the processing costs downstream of the wellhead. Superman Resources Inc. and Omers Resources bought all of the overriding royalty interests of seven of the Tencos in 1999. The owner of the other three Tencos commenced litigation in an attempt to have the royalty owners pay a share of the processing costs in 2000.



For future royalty contracts, the best approach is to clearly set out in the contract whether the royalty owner is responsible for a share of gas processing costs and for which gas processing costs the royalty owner is responsible.

Agreements

The agreement creating the royalty interest between Carter and Hamilton Bros. included the following clauses:

2.(a) The royalty on the Said Assets reserved by Vendor to itself upon the sale of the Said Assets to Purchaser and the royalty which Purchaser agrees the Said Assets are subject to is a limited overriding royalty of:

(i) 62.5% of the value of all petroleum substances produced from and/or allocated to the Said Assets. ...

(b) The limited overriding royalty reserved to Vendor shall be in addition to, and calculated after the deduction of the burdens.

(c) Any sale by Purchaser of any petroleum substances produced from the said lands shall include the Vendor's Royalty share thereof of Vendor. ...

(e) **The word "value" herein means the full price paid by a bona fide purchaser** (including any credit taken by such purchaser by virtue of any prior "take or pay" payment) **at the point of sale of the petroleum substances produced, saved and marketed from, or allocated to, the wells located on the said lands excepting the amount of the burdens.** (emphasis added)

"Burdens" was a defined term and the parties agreed that the gas processing costs at issue did not come within the meaning of that term. The agreement creating the royalty also included a covenant made by the purchaser to "perform all obligations of operating agreements, gas contracts, gas plant contracts and other contracts affecting said lands."

Decision

Justice Macleod dismissed the Plaintiff's claim for a share of the processing costs from the royalty owners on the basis that the owner of a royalty should not receive the benefit of processing without incurring any cost. Rather, Justice Macleod noted that a "royalty is a creature of contract and parties are free to enter into any arrangement including one under which gas processing fees are not to be deducted from the royalty." (para. 23).

In such a dispute, the court will normally focus on the plain ordinary meaning of the words in the contract to determine the point at which value is to be calculated. In this respect, Justice Macleod stated that when examining the royalty agreement, the Court "ought not [...] to superimpose the arrangement reflected by a 'typical' royalty on this particular one unless there are compelling reasons to do so" (para. 29). He noted, in particular, that there "was no custom or usage in the industry which would compel any particular interpretation of the agreements". In this case, the words provided only for the deduction of "burdens", which did not include gas processing costs. Consistent with this language, gas processing costs had never been deducted from the calculation of the royalty since their creation in 1979.

In interpreting a contract, the court may also consider the surrounding circumstances and conduct of the parties. Justice Macleod concluded that the applicable royalty agreement made it clear that Carter was to pay all costs and

expenses other than the burdens. This was consistent with the surrounding circumstances since both parties knew that the purchaser bought the assets and agreed to pay the costs associated with the tangibles and the oil and gas interests and, as noted above, gas processing costs had never been deducted from the royalty. Given the language agreed to by the parties and the circumstances of the transaction, had the parties intended to permit the deduction of gas processing costs prior to the calculation of the royalty, they would have done so in express terms. Accordingly, Justice Macleod determined that when the parties defined value as "the full price paid by a bona fide purchaser...at the point of sale...excepting the amount of the burdens" they deliberately decided to exclude processing costs upstream from the point of sale as deductions from the royalty calculation. (paras. 32-33).

Concluding Thoughts

On a first read, this case supports the principle that there is no rule of law in Alberta that royalty owners must pay a share of processing costs prior to the point of sale. Parties must begin by looking at the actual words used in their contract to determine this question. Justice Macleod did not speak in absolute terms, however, and qualified his reasoning in this decision in two important ways: first: by suggesting there could, in any given case, be "compelling reasons" to superimpose the arrangement reflected by a "typical" royalty; and second, by highlighting that the royalty in question was not a "typical" royalty transaction.

The scope of these qualifications is unclear. For existing royalties, the controversy continues. Most freehold leases, and many royalty agreements, do not adequately address this issue. In *The Oil and Gas Lease in Canada*³, John Ballam notes, for example, that in "practice, the average freehold lessor simply accepts the calculations and formulae used by the lessee and its accounting department." It could be argued that, one "compelling reason" for superimposing a "typical" arrangement on the calculation of a royalty, notwithstanding the plain and ordinary meaning of the words used in the contract, is that gas processing costs have previously been deducted in the calculation of the royalty without challenge. Consider this. If the tables were turned in the present case and gas processing fees had always been deducted from the calculation of the royalty, a challenge by the royalty owners to the calculation of the royalty after almost 20 years had passed might not have been successful.

For future royalty contracts, the best approach is to clearly set out in the contract whether the royalty owner is responsible for a share of gas processing costs and for which gas processing costs the royalty owner is responsible. The royalty owner should, as well, audit the calculation of the royalty from time to time to ensure that the royalty is being calculated in accordance with the provisions of the contract and not in accordance with an undefined "industry standard".

Footnotes

¹ Nigel Bankes, University of Calgary Faculty of Law Blog on Developments in Alberta Law, online:www.ablawg.ca

² 2008 ABQB 413

³ Ballam, J.B., *The Oil & Gas lease in Canada*, 4th edition, Toronto: University of Toronto Press, 2008 at 196, and quoted by Justice MacLeod at paragraph 31.

Shortage of CO_{2e} Offsets Predicted under Federal Regulatory Scheme

by John Goetz

Introduction

The re-election of Mr. Harper's Conservative minority government has signalled the go-ahead to proceed with regulations proposed under its Regulatory Framework on Air Emissions ("the Federal Framework"), announced in April 2008. Indications from government are that the Federal Framework is proceeding, with draft regulations now expected out in January, 2009.

As discussed in our earlier review of the Federal Framework¹, there are some significant differences between Alberta's Regulations and the Federal Framework. The focus of this article is the impact of the difference between the two schemes, that being the ability to use an unlimited amount of Technology Fund Credits under Alberta's regulations, and the more limited ability to use Technology Fund Credits under the Federal Framework. This article does not discuss harmonization between provincial and federal schemes, other than to assume that the more stringent scheme will prevail.

Key Differences Between Alberta Regulations and the Federal Framework

In Alberta, an emitter is able to meet its emission intensity reduction targets by buying Technology Fund Credits (1 credit

= 1 tonne of CO_{2e}). This means that if an emitter requires another 10,000 tonnes of emission intensity reductions, it can buy 10,000 Technology Fund Credits at \$15 per tonne to meet its compliance obligation. This \$15 per tonne price has effectively established the maximum price for one tonne of CO_{2e} reductions² under Alberta's Regulations.

The Federal Framework is different from Alberta's in that its focus is not only long-term emission reductions, but short-term reductions as well. In order to achieve short-term reductions, the federal scheme will only allow an emitter to achieve 70% of its compliance by way of Technology Fund Credits. The remaining 30% must be achieved by real intensity reductions. These real reductions can come from two sources: actual intensity reductions at the emitter's facility, or through the purchase of "Offsets". Offsets are generated by emission reduction activities of a non-regulated emitter that quantifies its reductions pursuant to an accepted quantification protocol, and then sells the Offsets to the emitter. Under the Federal Framework, the verified offset project will be submitted to Environment Canada and if the reductions are approved, certified offsets will be issued. Given that the government certifies these offsets, they have less risk than non-

certified offsets under the Alberta Regulations and because of this, will likely command a higher price. However, it is not the certified nature of the federal Offset that is likely to have the greatest impact on its price, but rather, the demand and supply of the Offset.

Challenges of the Federal Framework

Unlike the Alberta Regulations, the federal requirement to meet 30% of the reduction target by real reductions is expected to cause challenges. First, given the uncertainty surrounding the implementation of the Federal Framework to date, emitters now have only one year to react to the anticipated reduction requirements. In most cases, one year will not be enough time to achieve significant reductions at their facilities, since the introduction of technology and equipment to reduce or remove emissions can be extremely expensive, (up to hundreds of millions of dollars) and the lead time to plan, build, test and commission the systems is typically longer than one year. That leaves Offsets as the primary mechanism for emitters (at least outside of Alberta), to achieve the remaining 30% of their reduction targets. This means that most, if not all Canadian regulated emitters will be searching out Offsets to meet up to 30% of their compliance obligations.

There is no question that some emitters have been searching out projects and buying offsets in contemplation of the Federal Framework, but they are likely in the minority. Emitters have been penalized in the past for taking early action, only to find out later that their offset projects do not comply with new regulations.

Compounding this issue are a number of factors. First, the Federal Framework has a much lower emission threshold for regulation than the Alberta system, so it will capture a much larger number of emitters. Alberta regulates just over 100 large industrial emitters. The Federal Framework is expected to regulate thousands of emitters and require emission reductions from each. This will dramatically increase the volume of offsets required to meet reduction targets. Second, unlike Alberta, Environment Canada has to date effectively rejected the use of managed agricultural and forest sequestration programs as an accepted method of carbon sequestration. These sequestration programs are seen by many environmentalists as amongst the most effective means of removing carbon from the atmosphere. Afforestation and reforestation projects have been undertaken around the world to remove CO_{2e} from the atmosphere. However, following the lead of the CDM Executive Board, which is the body that approves Clean Development Mechanisms under the Kyoto Protocol, Environment Canada has cited the risk of events such as forest fires, pine beetles, crop fires and a return to tillage practices as reasons not to favour these types of sequestration programs to generate Offsets under their system. Where they would accept these programs, the discounting for risk is seen to be so onerous, that it negates any incentive to pursue such a sequestration project.

How significant is Environment Canada's decision not to accept meaningful volumes of emission reductions generated by agricultural and forestry projects as part of the federal Offset system? You only have to look to Alberta's experience to see the potential impact. Alberta's regulations required 12% reductions by emitters for the 1st compliance period, which was effectively 6 months from July 1, 2007 to December 31, 2007. About 5,700,000 tonnes (5.7 MT's) were required to meet reduction targets. Of the 5.7 MT's of reductions required in Alberta, 1 MT was achieved by way of offsets. About 65% of Alberta's Offsets were generated by agricultural sequestration projects. Given that this type of offset is not expected to be available under the federal scheme in any meaningful way, emitters will likely need to look elsewhere to fulfill their offset needs. The problem is that Alberta's history indicates this may be very difficult, if not impossible.

To look at how the federal numbers may develop, we have to examine the National GHG Inventory figures that the federal government released for 2006, showing Canadian Anthropogenic (caused by humans) GHG emissions were 721 MT's. This translates to about 360 MT's of regulated CO_{2e} emissions. We'll round this number down

to 300 MT's for this analysis. The Federal Framework will require industrial emitters to reduce emissions in 2010 by 18% (54 MT's) from the 2006 baseline. 70% of these (38 MT's) can be satisfied by purchasing Technology Fund Credits. That leaves 30% (16 MT's) to be satisfied by Offsets or at source intensity reductions. If we assume that half of this requirement is satisfied by at source reductions, (which will be a stretch), that will leave a requirement for **8 MT's** of Offsets. Herein lies the potential challenge. Alberta was only able to come up with 1 MT of Offsets, and 65% (650,000 MT's) of those Offsets resulted from agricultural sequestration projects. This means only 35% (350,000 MT's) resulted from non-agricultural projects. With Alberta alone making up almost 40% of Canada's industrial emissions, extrapolating to account for the other 60% translates to a total of only 875,000 tonnes of offsets. This raises the question: Where are the other **7 Mt's** of Offsets going to come from? This figure represents a need for **20 times** more non-agricultural Offsets than were generated to meet Alberta's 2007 reduction targets.

To put this in perspective, under the federal scheme, emitters will be able to draw on projects that have been generating verifiable emission reductions since 2008. So there will be 3 years worth of emission reductions in inventory to draw on (2008-2010). Compare this with Alberta, which could draw on emission reductions generated from 2002-2007 (6 years). When you consider Alberta emitters had twice as many years to generate its reduction offsets, and were only able to come up with 350,000 tonnes of non-agricultural offsets in that time, it makes the prospect of emitters obtaining sufficient offsets for their 2010 federal compliance even less likely.

Tight Timeframe

There is no question that some emitters have been searching out projects and buying offsets in contemplation of the Federal Framework, but they are likely in the minority. Emitters have been penalized in the past for taking early action, only to find out later that their offset projects do not comply with new regulations. The uncertainty surrounding the Federal Framework to date, including the fact that the proposed regulations may not be approved and finalized until near the end of 2009, and the uncertainty to date surrounding whether or not the government would even proceed with the current Federal Framework, has deterred emitters from taking early action, at least to the extent it would cost them money. Now, emitters will be in a very tight timeframe to meet their reduction targets, unless the federal regulations respond to address this issue.

Offset Pricing

The projected scarcity of federal Offsets will undoubtedly have a significant impact on Offset prices. Until now, Alberta emitters have had a price ceiling of \$15, by using unlimited Technology Fund credits to meet their target. This is no longer the case under the Federal Framework. The \$15 price that puts a ceiling on Alberta offsets has no relevance whatsoever under the Federal Framework. The key factor to determine the price will be supply and demand. The risk factor that affects the price of Alberta offsets is not present under the Federal Framework, since the Crown will issue all Offsets. As such, all Offsets will have the same intrinsic value, regardless of their source. This is distinct from Alberta, where certain offsets are seen to be less risky and therefore, more valuable.

Given the evaluation of the demand for offsets discussed above (8 MT's), and the constraints existing on the current supply of offsets, especially non-agricultural offsets, it is very likely there will be a large gap between the volume required and the volume available. To avoid non-compliance, emitters will have two options: find and pay market price for enough

offsets to meet their target; or pay a penalty for non-compliance, which, if like Alberta, will be \$200 per tonne. Offset aggregators, traders and project developers are predicting federal Offsets will be valued over \$20 per tonne and given their limited supply, may move toward the actual cost per tonne of reducing/sequestering emissions. The actual cost of reducing significant volumes of emissions has been estimated to be in the range of \$30-175 per tonne, depending on the type of emission source, with EOR and CCS schemes estimated to be in the range of \$30-\$80 per tonne. The international price for certified emission reductions (CER's) of CO₂e have been in the range of 15.00-23.00 (\$23.00-\$35.00 CAD) per tonne. As only 10% of Offsets can be satisfied through foreign CER's, the price range for CER's in the international markets is only an indicator. In addition, the volume of EUA's (European Union Allowances) available to foreign emitters to meet their targets has exerted downward pressure on the price of CER's. As such, they are not a very accurate price indicator for Canadian Offsets. Again, the key factor in Canada will be the limited supply in a closed Canadian system.

Conclusion

Assuming the new federal Regulations will be consistent with the Federal Framework, and the above analysis holds true, it may be prudent for emitters to seriously evaluate their emissions management and compliance programs to ensure that they will meet the challenges of more stringent reduction targets and more limited mechanisms with which to achieve them. The price of federal Offsets could potentially be much higher than that which Alberta emitters currently must pay. In the worst case scenario, if there are insufficient Offsets to go around, the emitters only alternative may be to pay a steep penalty for excess emissions. Hopefully, that will not be the case. Much of this problem could be avoided if the federal government allowed agricultural offsets along the lines of Alberta.

Footnotes

¹ BD&P Energy Matters Newsletter, March 2008

² In this article, when we refer to reductions, actual reductions or emission reductions, we are actually referring to reductions in emission intensity, since both the Alberta and the federal system are intensity based (ratio of emissions per unit of production).

What We've Been Up To

John Goetz and Morella DeCastro presented a paper, *Development of Carbon Emissions Trading in Canada* at the Canadian Petroleum Law Foundation's (CPLF) - Jasper Conference on June 26, 2008.

John Lowe and Jonathan Liteplo presented a paper, *Recent Regulatory and Legislative Developments of Interest to Oil and Gas Lawyers 2007-2008*, at the CPLF Conference in Jasper in June, 2008).

BD&P hosted a Breakfast seminar for oil & gas and insurance clients entitled *Emerging Risk Issues in the Oilsands* at the Hyatt on October 30, 2008. The Seminar was chaired by Donald Chemichen, o.c., and included a team of John Brussa, Patricia Quinton Campbell, John Goetz and Simon Lee.

Morella deCastro presented a paper at the II Oil and Natural Gas International Forum organized by the Brazilian Institute for Energy Studies on Nov. 3, 2008.

Rory Polson will be speaking on Gas Production Contracts on Nov. 18, 2008 as part of the 3 day *Introduction to Canadian Natural Gas Marketing* Conference presented by Phoenix Energy Marketing consultants Inc.

John Goetz is preparing a report of the Energy Resources Committee of the Alberta Economic Development Authority (AEDA) on recommendations for Carbon Capture and Storage and Enhanced Oil Recovery to be presented to the provincial government in December, 2009.

Alicia Quesnel is Past President of the CPLF.

Carolyn Wright is currently a Director of the CPLF and a member of the Organizing Committee for the CPLF Jasper Conference as well as co-chair of the CPLF Kananaskis Seminar in Fundamental Oil & Gas Law. Carolyn is an executive member of the Canadian Bar Association ("CBA") Natural Resources Section.

Morella deCastro and Candice Jones teach a bi-annual course on *Freehold Lessor Estates* to the Canadian Association of Petroleum Land Administrators ("CAPLA").

Candice Jones is a Director-at-Large Legal of the Petroleum Joint Venture Association ("PJVA").

Stuart Money annually teaches "A Practical Guide to Title Review and Acquisitions" and "An Interpretive Approach to Dealing With ROFR Issues" for the Canadian Association of Petroleum Landmen Continuing Education Program.

John Taylor is back at the firm and wishes to thank all clients and friends who have been so supportive of him and his family during his recent illness and convalescence.



Weyerhaeuser V. Hayes:

Reconsidering The Law of Assignment

by Aaron Rogers

Introduction

The assignment of a contract is a common business practice that is often considered routine and consequently, is carried out with little concern. Unknown to most people, however, is that the law of assignment is actually quite complicated with interesting historical foundations. As a result, the effects of an assignment on the liability of both the assignor and the assignee should be carefully considered and well understood to ensure that contractual liability is borne solely by the intended party.

Benefits vs Burdens

The well-established principles of the law of assignment distinguish between the assignment of benefits and the assignment of burdens. Benefits can generally be freely assigned subject to specific categories of contracts that are recognized as exceptions and for which assignments are not permitted.

Those exceptions include contracts where the skill or ability of the assignor has been specifically contracted for and contracts which would be difficult or impossible to satisfy once assigned.

Burdens or obligations, on the other hand, cannot generally be assigned. However, even if the assignee agrees with the assignor to assume the burdens or obligations of the contract, the law generally provides that, without the agreement of the counterparty, the assignor nonetheless continues to remain responsible to the counterparty for the fulfillment of the obligations and the counterparty is not bound to recognize the assignee as having any rights under the contract. The assignment contract itself may, of course, provide for indemnities between the assignor and assignee and permit the assignor to sue the assignee for the non-performance of assigned obligations for which an action has been brought against the assignor.

The significance of *Weyerhaeuser* is that it recognizes that an assignor may be relieved from liability for contractual burdens without novation if the express terms of the contract so provide.

A Novation Agreement

In order for the assignor of a contract to be relieved of liability and for an assignee of a contract to be recognized by the counterparty as having rights and obligations under the contract, an agreement known as a “novation” is generally required. The Supreme Court of Canada has defined novation as “a tripartite agreement by which an existing contract is extinguished and a new contract brought into being in its place” by agreement between the existing contractual parties and a new party: *National Trust Co. v. Mead*¹. Under a novation agreement, the assignee agrees with the assignor and the counterparty that it will be bound by the burdens and obligations of the contract, the counterparty consents, privity of contract between the assignee and the counterparty is established and, unless the novation agreement otherwise provides, the assignor is relieved of its liability to the counterparty under the contract.

The Weyerhaeuser Case

The recent British Columbia Court of Appeal case of *Weyerhaeuser Co. v. Hayes Forest Services Ltd.*² (“*Weyerhaeuser*”) deals squarely the issues raised above and makes a significant finding with respect to the ability of an assignor to be relieved from liability under a contract without novation. *Weyerhaeuser* was the holder of a forestry license (the “TFL 44”) and had entered into a Timber Supply Execution Agreement (the “TSE”) with Hayes Forest Services Limited (“Hayes”) for timber harvesting within the license area. Pursuant to that agreement, *Weyerhaeuser* agreed not to transfer or assign either the TFL 44 or the TSE unless they were transferred or assigned to the same party and that party consented to being bound by the terms of the TSE. *Weyerhaeuser* subsequently assigned both the TFL 44 and the TSE to Cascadia Forest Products Ltd. (“Cascadia”) who agreed to be bound by the TSE. Despite apparent compliance with the requirements of the TSE, however, Hayes took the position that *Weyerhaeuser* remained liable for its obligations under that agreement.

It was apparent in *Weyerhaeuser* that no novation had occurred, either expressly or by conduct. A unanimous Court of Appeal found, however, that *Weyerhaeuser* was relieved of its liability to Hayes and was no longer bound by the TSE. Speaking for the Court, Mr. Justice Low rested his decision on the

fact that the terms of the TSE expressly provided for the substitution of one contracting party for another without the need for novation. By complying with the express requirements of the TSE respecting assignment, which did not require the consent of Hayes, *Weyerhaeuser*’s contractual obligations to Hayes were extinguished, Cascadia was substituted as a party to the TSE and Hayes was bound to look to Cascadia for performance of the contract.

The Significance of Weyerhaeuser

The significance of *Weyerhaeuser* is that it recognizes that an assignor may be relieved from liability for contractual burdens without novation if the express terms of the contract so provide. A similar position appears to have been taken in the recent Ontario Court of Appeal decision of *SimEx Inc. v. IMAX Corp.*³, (“*SimEx*”). In that case, the assignor was expressly provided with a right of assignment in the applicable contract. Although it was held on the facts of the case that the assignor had not actually assigned the contractual obligations at issue, Mr. Justice Rosenberg stated for the Court of Appeal that, as a result of the contractual right of assignment, the assignor may have been able to transfer its liability for performance onto an assignee contrary to the general prohibition against doing so. (para. 45).

As a result of the findings of the Court of Appeal in *Weyerhaeuser* and the statement made by Mr. Justice Rosenberg in *SimEx*, there now appears to be two Canadian court of appeal decisions recognizing that, where the terms of the contract so provide, novation is not required to relieve an assignor of the burdens and obligations of a contract or to establish privity of contract between the assignee of a contract and the counterparty.

Although it is arguable whether *Weyerhaeuser* represents an extension to the law of assignment or merely clarifies an existing element that was not well developed in prior case law, the impact of this decision to the contractual relations between companies is significant.

Footnotes

¹ [1990] 2 S.C.R. 410

² 2008 BCCA 69

³ [2005] O.J. No. 5389 (C.A.)

Update on Klemke Mining Corp. v. Shell Canada Ltd.

A discussion of the Alberta Queen’s Bench decision in this case was our feature article in our June 2007 Newsletter. The case was appealed by Shell Canada Limited and the other Defendants to the Alberta Court of Appeal ([2008] A.J. NO. 725) where the appeal was dismissed. The Court of Appeal found that the evidence supported the conclusion of the trial judge that there was an enforceable contract between Klemke Mining Corp. and the Defendants for advisory and consulting services and mining work on the Muskeg River Mine project.

Accordingly, our thoughts on the lessons to be learned from the Klemke decision continue to hold as follows:

The most important lesson to be gleaned from *Klemke* is that during negotiations, parties should make it clear that documents are for discussion purposes only and should refrain from making oral assertions that would lead a party to prematurely believe that a final binding agreement has been reached.

Further, careful notes should be taken of all interactions so that memories can be refreshed should disagreements arise as to the existence or terms of agreements. Justice Smith admitted to being more inclined to believe the KMC’s witnesses since they had more detailed and careful notes and appeared to better recollect the events.

Finally care should be taken to ensure that individuals without authority to bind the joint venture to agreements are not held out as having such authority. *Klemke* demonstrates that binding contractual obligations can be found notwithstanding the absence of a formal written contract.



BD&P Sponsors Homeless Connect 2008

The Calgary Homeless Foundation held Project Homeless Connect (PHC) on Saturday, September 20, 2008 at the Calgary Municipal Building. The event provided services from fifty local agencies and organizations to more than 800 homeless or near-homeless individuals and families – all under one roof.

Services provided included housing, medical treatment, counselling, assistance with new identification documents, access to income support and employment opportunities. Calgary Legal Guidance was on hand to provide legal advice to homeless and low income Calgarians. In addition, the event provided participants with healthy snacks, sandwiches, work boots, used clothing and “comfort kits” which contained soap, shampoo, comb, hand sanitizer, and more.

BD&P, a long time supporter of the Calgary Homeless Foundation, provided financial support and volunteers for the event. BD&P partner, Brian O’Leary, Q.C. and his wife Anne served coffee and sandwiches. Legal assistants Amanda Cutting and Carolyn Dean served as greeters and helped individuals complete resumes for job applications.

The next Project Homeless Connect will be held November 29, 2008.

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