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VALUING ENERGY RESOURCES: REFLECTIONS ON THE EUB'S DECISION IN THE SURMONT "GAS OVER BITUMEN" CONTROVERSY

Article by Michael M. Wenig ♦

Introduction

Are all fossil fuels created equally? How should fossil fuels be valued relative to other energy sources and the environmental resources lost or harmed by fossil fuel production?

These questions underlie an ongoing controversy in Alberta between producers of "bitumen" and "associated gas." The former is the heavy, viscous crude oil in "oil sands"; the latter is natural gas immediately overlying *in situ* oil sands, which are oil sands that are located deep beneath the surface.

The "gas over bitumen" controversy has arisen from claims that the production of associated gas could significantly impair production of bitumen, and possibly vice versa. The controversy reached its first peak when Gulf Canada Resources Ltd. ("Gulf"), the holder of rights to produce bitumen in the "Surmont" area, requested the Alberta Energy and Utilities Board ("EUB" or "Board") to "shut in" numerous associated gas wells in order to protect the productive capacity of Gulf's bitumen reserves. The Board granted Gulf's request while recognizing that the gas producers should be compensated for their losses.[1]

The Board's solution is of great public interest because of the large volumes of energy resources and public and private dollars at stake, in the Surmont context, and in the several other areas of Alberta where the "gas over bitumen" dispute is now being played out. However, the Board's solution is of additional interest in providing a reflection of how the province generally values its fossil fuel resources. This general valuation, in turn, has implications for a broad energy policy that must make choices between fossil fuels and so-called renewable energy sources and between fossil fuels and the environmental services or resources – e.g., air, water, habitat, wildlife – that are lost or reduced in the production of those fuels.

This paper addresses the Board's abstract method for valuing the Surmont gas and bitumen, with these broad implications in mind.

The Surmont Dispute and the Board's Solution

For purposes of this paper, the Surmont controversy arose in 1999, when Gulf requested that the EUB shut in 183 gas wells.[2] To access its bitumen, Gulf intends to use a technology which involves heating the bitumen with large amounts of steam so that it can be brought to the surface in wells like conventional oil. However, according to Gulf, the success of this process is dependent on retaining the pressure overlying the bitumen. In Gulf's view, production of the associated gas would reduce this pressure and thereby impede bitumen production.

Gulf estimated that it could recover 35-50% of the 15-17 billion barrels of bitumen covered by its Surmont leases as long as the gas pressure was maintained.[3] The EUB's decision does not make clear just how much of that recoverable bitumen would be lost if the associated gas was produced, but the Board referred to Gulf data suggesting losses ranging from one-third to roughly 100%.[4]

The Surmont gas producers challenged Gulf's assessment of its risk of loss, by pointing out several technologies for restoring any pressure lost from continued gas production. However, the Board rejected

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RÉSUMÉ

Cet article examine la façon dont le gouvernment de l'Alberta évalue les ressources en hydrocarbures. À cette fin, l'auteur analyse la décision prise par l'Energy and Utilities Board (l'Office) en 2000 de fermer de nombreux puits de gaz dans la région de "Surmont" dans le but d'assurer la viabilité du développement du bitume dans un vaste gisement in situ de sables bitumineux sous-jacent au gaz de Surmont. En un mot, l'Office a fondé sa décision sur sa conclusion que le bitume de Surmont pouvait fournir un rendement brut en énergie beaucoup plus important que le gaz "associé" à ce bitume. L'auteur conclut que la méthode utilisée par l'Office pour comparer les valeurs du gaz de Surmont et celles du bitume ne tient pas compte des nombreux coûts et avantages sociaux liés au développement de ces ressources. Il suggère diverses modalités d'évaluation alternatives qui, tout en étant imparfaites, pourraient fournir une meilleure base d'évaluation complète des valeurs sociales de ces ressources. Enfin, l'auteur suggère que la modalité d'évaluation des ressources énergétiques utilisée par l'Office a des conséquences négatives pour une politique énergétique d'ensemble visant à résoudre les conflits, non seulement entre les ressources en combustibles fossiles, mais aussi entre les combustibles fossiles et les autres sources d'énergie, et entre les sources d'énergie et les valeurs environnementales qui sont perdues ou menacées du fait de la production énergétique.

these options as technically uncertain and likely to take so long to implement that they could have a "significant negative impact on the economics of" the project.[5]

What about the effect on the remaining natural gas of allowing the bitumen to be produced first? Gulf conceded that this sequence would result in a "loss" of gas; the gas producers argued more bluntly that a shut-in would be tantamount to a taking of their entire remaining gas resources because of the potentially long time (up to 200 years) it might take Gulf to produce all the bitumen.[6] In response, the Board treated the takings claim as essentially a compensation issue. The Board also acknowledged that there could be a "loss" of associated gas but deferred reaching definitive conclusions in light of the lack of evidence submitted at the hearing on this technical issue. The Board cautioned, however, that Gulf would be expected to address this issue in later applications for bitumen recovery.[7]

With these countervailing risks in mind, the Board considered the relative volumes of the Surmont gas and bitumen at stake. According to the Board, the volumes of remaining recoverable gas were "in the order of half of one percent" of the total recoverable volume of bitumen on an "oil equivalent" basis; and the bitumen was itself a "significant energy resource for the province" when compared to crude oil production generally. Under these circumstances, the Board concluded that the "potential value" of the bitumen "significantly exceeds" the "value" of the remaining gas and that it would "not be in the public interest to accept the possibility of sterilizing a vast bitumen resource by allowing continued gas production."[8]

Given these conclusions, the Board granted Gulf's shut-in request with respect to 146 of the 183 wells.[9] The Board recognized, however, that the gas producers should be compensated, but left it to a later time to establish the compensation scheme.[10]

The Board's decision and underlying rationale reflected a *zero-sum* approach to resolving the Surmont gas over bitumen dispute, at least, with respect to gas and bitumen production.[11] This approach is evident in part from the solutions the Board did *not* adopt. One solution might have been to order a production moratorium for *both* the gas and bitumen in order to spur the development of technical solutions that would ensure both resources could be produced concurrently. Another solution might have been to at least defer production of both resources pending the development of better information to clarify the precise *extent* of each resource that might be jeopardized by the production of the other.

Rather than take either of these approaches, the Board simply shut in the associated gas wells to avoid any risks to bitumen production, while deferring its consideration of whether bitumen production would jeopardize associated gas production. By not addressing the risks to gas production up front, the Board's decision implies that the Board would have shut in the gas wells even if the record was *clear* that a shut in to allow future bitumen production would preclude further Surmont gas production.

The remainder of this paper addresses the Board's "oil equivalence" methodology for comparing the values of the gas and bitumen reserves, taking the Board's implied zero-sum framework as a given.

Valuing Gas and Bitumen on an "Oil Equivalent" Basis

The Board purported to apply the "oil equivalence" standard in order to fulfill its overall mission which is to promote the "public interest."[12] The "public interest" mandate implicitly requires the Board to consider all relevant public benefits and costs, including environmental costs.[13] This paper presumes that the "public interest" also requires the Board to maximize public welfare or social value in light of those public benefits and costs.

From this "public interest" standpoint, the Board's use of the "oil equivalence" standard for comparing the values of two different resources is problematic, because that standard values only energy output, in *joules* or *calories*.[14] As such, it does not capture the full range and magnitude of social costs and benefits of gas and bitumen and, thus, does not reflect the "public interest" in those resources.

There are several reasons for this shortcoming. First, neither natural gas nor bitumen is used entirely to produce energy. Both natural gas (or its derivative "natural gas liquids") and bitumen are used for both non-energy end uses (e.g., for producing petrochemicals, lubricants, and asphalt) and as blends for producing refined fuels.[15] It seems unlikely that the relative social *values* of the non-energy uses of natural gas and bitumen are captured by those resources' relative oil equivalence.

Second, gas and bitumen are used to produce different *kinds* of energy. The primary energy-related end use for crude oil – including refined bitumen – is in the transportation sector. By contrast, natural gas has historically been important for residential heating and is becoming a major source of electricity.[16] The "oil equivalence" standard does not capture the different relative social values of the benefits of even the energy-related end uses of gas and bitumen.

Third, the social value of an end-use of energy is determined, not only by the *benefits* provided by the end use, but also by the costs and benefits of producing the energy in the first place and by the costs of using the energy. These factors vary between gas and bitumen for the same end uses of those resources, so equal "oil equivalent" units of each of the two fuels do not have the same social value even when the two fuels are put to the same use.

For example, gas is generally a cleaner source of electricity than crude oil (and coal) from an air pollution standpoint. This advantage has made gas an increasingly desirable source for electricity generation.[17] On the upstream side, both natural gas and bitumen production impose a variety of direct environmental costs including those related to water and air pollution, habitat destruction and alteration, wildlife disturbance, and water consumption.[18]

An industry trade journal editorial recently described bitumen production as a "dirty business." The editorial suggested that controlling pollution from bitumen production was a matter of "growing urgency" and that the industry had a "responsibility" to take a "hard look" at what bitumen production was "doing to the environment".[19] Of course, natural gas production has not been immune from criticism on environmental grounds.[20]

The "oil equivalence" standard also ignores costs stemming from the energy needed to produce natural gas and bitumen. Bitumen production is generally more energy intensive than natural gas production, although the precise relation varies depending on the location of the particular energy source and other site-specific factors.[21] In fact, much of the energy needed for bitumen production is expected to come from natural gas.[22]

Whatever the correct energy input/output ratio, the *gross* "oil equivalence" approach used by the Board does not reflect the relative social costs from the differing amounts of energy needed to produce gas and bitumen. These costs include the environmental cost of producing, shipping, and refining the energy needed to produce natural gas and bitumen, as well as costs relating to energy security.

Still another factor bearing on the relative values of two fuel sources is the time in which each source is likely to be produced. In the Surmont case, the record suggested that Gulf did not plan to produce its entire bitumen leases for 100-200 years, whereas the gas producers intended to produce their remaining gas reserves in a relatively short time. Gulf's planned timing of bitumen production may have social costs and benefits that bear on the overall "public interest" at stake.[23]

Rather than consider how the contrasting production times for the Surmont gas and bitumen affected those resources' relative social values, the Board treated the timing of production as irrelevant to its valuation of the two fuel sources.[24]

Alberta's Energy Minister stated recently that, in the last decade, natural gas has become the "fuel of choice" for a "growing share of North America's energy needs."[25] This is an overstatement in that gas has not materially replaced crude oil as an energy source for transportation and possibly other traditional uses of crude oil. But the Minister's statement underscores the point that equal oil equivalents of natural gas and bitumen do not have equal social values.

Notwithstanding the theoretical shortcomings of the "oil

equivalence" standard, perhaps "oil equivalence" is a reasonable proxy or short cut for a full social value comparison of two energy resources where, as with the Surmont gas and bitumen reserves, one resource is vastly larger than another on an "oil equivalence" basis. But the Board's Surmont decision did not purport to use "oil equivalence" on this basis, let alone provide the technical analysis that would presumably be necessary to support that proxy relationship.

If the Board's "oil equivalence" valuation method is too simplistic, what method is more appropriate? The next section discusses the valuation method urged by the gas producers and the Board's rationale for rejecting that method.

The Gas Producers' Alternative: Economic Value

The Surmont gas producers argued that a more appropriate measure of the relative social values of the gas and bitumen resources was their relative present *economic* value. Under this approach, the gas producers argued that, while the gas reserves had a present value in the hundreds of millions, the discounted value of the bitumen reserves was essentially zero in light of Gulf's 100 to 200 year schedule for producing those reserves.[26]

Does economic value provide a more accurate basis than oil equivalence for determining the relative social values of the Surmont bitumen and gas reserves? On the one hand, many of the social values discussed above are arguably reflected in the market prices for those resources, which prices were used for calculating the resources' present economic value.

On the other hand, not all of those social values are reflected in the market price, because many of the resources' social costs, particularly, environmental costs, are externalities – i.e., they are not reflected in the costs of producing those resources and hence in the price paid for them.[27]

The Board's response to the gas producers' present value argument is interesting both for what the Board said and what it did not say. As to the latter, the Board did not contradict or question the accuracy of the gas producers' present economic value calculation. Instead, the Board seemed to read the gas producers' argument as implying that the EUB should require Gulf to produce the bitumen more rapidly, presumably, to provide a higher present economic return. The Board then responded that it would be unreasonable for the Board to change Gulf's production schedule because that action might result in "ill-timed" investments. In its very next breadth, the Board reasoned that it was required to "consider a broader set of issues than the immediate plans of any one company or industry sector."[28]

The Board's explanation is confusing, in part, because the Board did not identify the "broader set of issues" and its reliance on the "oil equivalence" standard hardly constitutes consideration of a "broad set of issues" given the narrow focus of that standard.

The Board's explanation also avoided addressing whether Gulf's extended production schedule provides values or imposes costs to society that are not reflected in the present economic value of the bitumen resulting from the schedule.

An economist might argue that the market – as reflected in the decisions of the oil and gas producers – is the best method for choosing the timing of fossil fuel production in order to maximize social welfare and thus promote the "public interest". But, once again, this theory works (on its own terms) only if all social costs and benefits are internalized in the prices generated by the market. As explained above, that 'perfect market' condition does not exist.

In sum, the present economic valuation made by the gas producers took a step beyond "oil equivalence" in reflecting the comparative social costs and benefits of the Surmont gas and bitumen reserves. But the economic approach itself fails to account for all social costs and benefits.

Beyond Present Value and Oil Equivalence

The above critique of the Board and gas producers' comparative valuations begs the question: What valuation method should the Board have adopted, if "oil equivalence" and "present economic value" are too short sighted? Unfortunately, there are no clear, easy alternative valuation methods. The following discusses two approaches that warrant further consideration.

One alternative would be for the EUB (or Alberta Energy, at the leasing stage) to chose among energy resources whose production may be in conflict with each other, based on a "full cost accounting" of those resources. As its name suggests, "full cost accounting" attempts to itemize the full range of the resources' social costs and benefits.[29] This exercise sounds logical, but it is technically complex, it generally requires the use of value judgments that detract from the supposed objective or 'scientific' nature of the exercise, and it requires numerous assumptions whose accuracy may be questionable.[30] Assumptions about

technological capabilities are particularly difficult in light of the potentially rapid rate of technological change in the energy production sector and the potentially long production time frames.

However, for all its difficulties and inaccuracies, full cost accounting would still provide a more accurate reflection of the relative social values of gas and bitumen than the time-independent, gross "oil equivalence" measure embraced by the Board.

An alternative to a government-conducted full cost accounting would be for the government to use tools that force fuel producers to internalize the costs of their production and then let the market for those fuels decide which is more valuable. This approach would be more advantageous than full cost accounting because it would arguably provide a more direct, immediate financial incentive for energy producers to modify their operations in order to improve their social cost/benefit ratio. This approach could also avoid the failure of a one-time full cost accounting to reflect changes in new technology and other factors.

Yet, as with full cost accounting, internalizing costs is problematic. It requires a monetary valuation of ecological services and other 'goods' whose full value is difficult if not impossible to quantify. It may not result in 'correct' energy prices charged to consumers unless costs are internalized on the same geographic basis as that on which the market price for the energy is set. And the methods for internalizing costs – e.g., pollution taxes, royalty incentives – may be technically and politically difficult to implement. However, as with "full cost accounting," this approach at least *attempts* to capture the full range of social costs and benefits, unlike the EUB's approach of comparing the Surmont gas and bitumen on a gross, time-independent "oil equivalence" basis.

Conclusions

As a practical matter, where two energy resources have vastly different "oil equivalents," as with the Surmont gas and bitumen reserves, "oil equivalence" may be a reasonably rough measure of the resources' comparative social value. But the appropriateness of that measure should be carefully considered and determined rather than simply assumed.

Absent such determination for the Surmont gas and bitumen, the EUB's "oil equivalence" valuation failed to account for the full range of social costs and benefits of the gas and bitumen at stake, especially, when the EUB considered "oil equivalence" on a gross basis and without regard to when those resources would be produced.

The present economic valuation approach urged by the Surmont gas producers captured social values reflected in the market prices for the gas and bitumen, but still did not reflect a full social value comparison because of the market's failure to internalize all social costs and benefits.

The "full cost accounting" and cost-internalizing, market-based alternative valuation methods are themselves problematic but at least make a better attempt to value social costs and benefits than the Board and gas producers' valuation approaches.

Since the Surmont dispute arose, Alberta Energy has taken a more proactive leasing approach in other areas to avoid generating conflicting gas and bitumen leases in the first place.[31] This approach may reduce the need for the *EUB* to resolve gas over bitumen disputes in the long term, but it shifts the valuation problem to Alberta Energy rather than eliminate it entirely.

Technological developments may well eliminate or greatly reduce the "gas over bitumen" conflict in the long term. Yet, the problem of comparing resource values applies, not only in the "gas over bitumen" context, but also more broadly to a wide range of resource allocation decisions. If, in making these decisions, the government values gas and bitumen, or fossil fuel resources generally, on an "oil equivalence" basis, the government may be over-valuing those resources relative to other energy sources and selling short the environmental services that are jeopardized by fossil fuel production. These problems should be explored, if not in the "gas over bitumen" context, then in the context of a broader energy policy and framework for sustainable development.

♦ Michael M. Wenig is Research Associate, Canadian Institute of Resources Law. The author would like to thank his colleague Steven A. Kennett and Professor Nigel Bankes for their comments.

Notes

1. EUB, Decision 2000-22, Gulf Canada Resources Limited – Request for the Shut-in of Associated Gas – Surmont Area (March 2000).
2. *Ibid.* at 2-3. The controversy actually arose in an earlier shut in request by Gulf that led to a public inquiry and follow up regulations and litigation. See Nigel Bankes, "Recent Developments in Canadian Oil and Gas" (Winter, 2001) 73 *Resources* 9-10. While significant in its own right, that history is irrelevant for purposes of the issues addressed in this paper. In addition, the controversy has arisen in several other geographic areas. The EUB's final decisions on requests to shut in gas production in those areas are still pending.
3. *Ibid.* at v.

4. *Ibid.* at vi, 6, and 81.
5. *Ibid.* at vi.
6. *Ibid.* at 80; *Submission of the Surmont Producers*, EUB Proceeding No. 960952 (March 8, 1999) at 70.
7. *Ibid.* at 80.
8. *Ibid.* at v and 82-83.
9. In the Board's view, the remaining 37 wells did not need to be shut-in because some of them were outside of the relevant geologic formation and the rest contained gas that was not "associated" with the underlying bitumen. *Ibid.* at vii.
10. *Ibid.* at vii.
11. The Board's solution is not *zero-sum* in the sense that it provided for the gas producers to be compensated for their production losses.
12. *Ibid.* at vii. See *Energy Resources Conservation Act (ERCA)*, R.S.A. 2000, c. E-10, s. 3.
13. Section 3 of the *ERCA* actually makes express the mandate to consider environmental costs as part of an overall public interest consideration.
14. International Energy Agency (IEA), *Million Tonnes of Oil Equivalent*, www.iea.org/stats/files/mote.htm (visited 9/30/02).
15. National Energy Board, *Canadian Energy – Supply and Demand to 2025* (1999) at 25 [hereinafter NEB]; Hon. Murray Smith, "Heart of North American Energy Security" (Notes for a speech to the Arctic Gas Symposium, November 29, 2001) at 6.
16. *NEB, supra* note 15 at 2, 53; Natural Resources Canada, *Energy in Canada 2000* (Ottawa: 2000) at 51-52.
17. As Alberta's Energy Minister stated recently, the "[g]reater use of natural gas reduces environmental liabilities associated with some other energy forms." Smith, *supra* note 15 at 25.
18. See, *e.g.*, Richard B. Schneider, *Alternative Futures – Alberta's Boreal Forest at the Crossroads* (Edmonton: Federation of Alberta Naturalists, 2002) at 56-59.
19. Andrea Lorenz, "The Language of Kyoto" (September 23, 2002) Oilweek Newsletter at 8.
20. *E.g.*, Schneider, *supra* note 18 at 56.
21. See generally, *e.g.*, Gordon Jaremko, "Oilsands Breakthrough", *Oilweek* (June 3, 2002) at 26 (noting that the energy needed to produce oilsands has "always been a source of debate with conservationists and a stimulus for engineering work" and that one oilsands producer reported an overall energy efficiency of 77%).
22. Smith, *supra* note 15 at 11 (noting that the biggest growth in demand for natural gas will come from the industrial sector, particularly oil sands development, which has "major natural gas needs").
23. Still another cost stems from the loss in present *economic* value resulting from a long production schedule. This cost is discussed in the next section of this paper.
24. EUB Decision 2000-22 at 82-83.
25. Smith, *supra* note 15 at 2.
26. EUB Decision 2000-22 at 81-82.
27. See, e.g., Arlon R. Tussing, "An Economic Overview of Resource Disposition Systems" in Nigel Bankes & J. Owen Saunders, eds., *Public Disposition of Natural Resources* (Calgary: Canadian Institute of Resources Law, 1984) at 25.
28. EUB Decision 2000-22 at 82; see also *ibid.* at vii (similar discussion in the Executive Summary).
29. See, *e.g.*, Jan Bebbington *et al., Full Cost Accounting: An Agenda for Action* (London: Association of Chartered Certified Accountants 2001) (www.accaglobal.com/publications/research_reports).
30. See, *e.g.*, Kristin Dawkins & Chirag Mehta, "PCDF Forum Column #56 - Getting Prices Right: Only a Partial Answer" International Institute for Sustainable Development (June 25, 1993) (www.iisd.org/pcdf/1993/56dawkin.htm).
31. See Alberta Energy, Information Letters 2000-36 (December 15, 2000); 2001-13 (July 18, 2001); 2001-21 (July 18, 2001); and 2002-07 (February 25, 2002).

RECENT DEVELOPMENTS IN CANADIAN OIL AND GAS LAW

Article by Nigel Bankes

Two Cases on Termination During the Secondary Term

John Ballem's book, *The Oil and Gas Lease in Canada*, and his many articles on the oil and gas lease, are testimony to the ample case law that exists on the adventitious termination of the lease either during, or immediately at the end of, the primary term. The body of case law on the termination of the lease during the secondary term, perhaps following a period of production or a long shut-in period, is much smaller; hence, the interest in two relatively recent decisions, that of Justice Romaine in *Freyberg* v. *Fletcher Challenge Oil and Gas Inc.*, [2002] A.B.Q.B. 1173 and that of the Saskatchewan Court of Appeal in *Montreal Trust Co.* v. *Williston Wildcatters Co.*, [2002] S.K.C.A. 91, aff'g the trial judgement of Gerein C.J., [2001] S.K.Q.B. 360.

Freyberg

Reduced to the bare essentials, the facts of *Freyberg* were as follows. Freyberg was the successor in title to a two thirds undivided interest in a gas lease granted November 13, 1975 for a five-year primary term and continuing for so long as the leased substances are produced from the lands, "subject to the continuation, further extension or sooner termination of the said term as hereinafter provided." The fourth proviso to the habendum stipulated that:

> "PROVIDED that … subject only to Clause 3 hereof, if any well on the said lands … is shut-in … as the result of a lack of or an intermittent or uneconomical or unprofitable market, or any cause whatsoever beyond the Lessee's reasonable control, the time of such interruption or suspension or non-production shall not be deemed a discontinuance of … production … anything herein elsewhere contained or implied to the contrary notwithstanding."

The shut-in clause of the lease (cl. 3) provided that, at the expiration of any year during the secondary term, where there is a designated gas well on the lands from which no leased substances are being produced as the result of the lack of an economic or profitable market, such a well shall be deemed to be a producing well and "the Lessee shall, on or before such anniversary date, pay to the Lessor in the same manner provided for the payment of delay rental hereunder, as royalty, an amount equivalent to the delay rental. Like payments shall be made in a like manner on each successive anniversary date during the period such well is deemed by virtue of this Clause to be a producing well …".

The manner of payment clause had a deemed timely receipt clause that would be triggered if a cheque was mailed at least 48 hours before the anniversary date of the lease. The default clause of the lease purported to apply to any any "breach or non-observance or non-performance" by the lessee of "any covenant, proviso, condition, restriction or stipulation" contained in the lease. It stipulated that the lessor could only exercise its right of re-entry in the event that it had given the lessee notice and the opportunity to remedy a default. Exercise of the right of re-entry was also subject to the proviso that the lease could not be terminated for so long as there was on the lands "a well capable of producing the leased substances".

Fletcher's predecessor in title drilled the 6-3 well in October 1978; a drill stem test in the Glauconitic formation gave a steady flow in excess of 6 million cubic feet per day. No further operations to complete or put the 6-3 well on production were undertaken for nearly 20 years. Over this period production did occur from wells on adjacent properties which produced for relatively short periods of time before being shut-in for excessive water production and subsequently abandoned. The evidence showed that the 6-3 well was up-structure of these wells and not subject to excessive drainage. Efforts to get the 6-3 well on production were frustrated by a number of factors including: (1) the intransigence of the operators of the local gas plant and gathering facilities, (2) the economics of constructing additional facilities, and (3) lack of access to regional gas sales agreements. While the lessee threatened the operators with an application to the Board for common carrier and common processor relief, no action was taken.

Fletcher completed and tested the 6-3 well in November 1998. The operation was very successful and the well was put on production in December 1999 resulting in significant royalty payments to Freyberg. Because of improved gas prices, royalty payments were significantly higher than they would have been had production occurred during some or all of the shut-in period.

Freyberg sought a declaration that the lease had terminated either, on the basis that two of the nineteen shut-in royalty payments were not made in a timely manner, or on the basis that there was an economic or profitable market for production from the well before production commenced in 1999. Freyberg's claim was dismissed. The case stands for a number of important propositions. I shall summarize those propositions and then comment on two issues: (1) the interpretation of the habendum and the shut-in clause, and (2) the claim that termination during the secondary term is somehow different from termination during the primary term and the associated issue of the court's interpretation of the proviso to the default clause of the lease.

Here are the propositions. (1) Oil and gas lease litigation is subject to the general rules on onus of proof. There is no rule of law that invariably requires the lessee to bear the onus of showing that its lease is still valid. (2) A lessee wishing to rely on a deemed receipt of a shut-in payment will have the onus of proof even when a defendant. (3) Where the lessor alleges that a lessee cannot rely upon a shut-in clause because the lessee has failed to meet a condition precedent for doing so relating to the absence of a market, the lessor will have the onus of proving absence of a market, at least where the lessor is the plaintiff. (4) Where the manner of payment clause allows for deemed receipt, evidence of late actual receipt of payments will not be relevant.
(5) Termination during the secondary term should be treated differently than termination during the primary term. (6) Each oil and gas lease should be interpreted on the basis of its actual provisions. The court should be wary of general propositions of law in relation to oil and gas leases. (7) A post-dated cheque is a cheque for the purposes of the oil and gas lease, even if it is not for the purposes of the *Bills of Exchange Act.* (8) Inferentially, one tenant in common of the lessor's interest in a lease can sue for termination of the lease even though the other tenant in common of the lessor's interest wishes to uphold the lease. (9) The proviso to the default clause protects the lease from automatic termination. (10) Where the court must determine whether there was a market for lease production, the court will ask whether it was reasonable, at the relevant time, for the lessee to have formed the view that there was no viable market for the gas. The relevant time will be each anniversary date of the well. The court will have regard to a variety of factors including price, the potential for sustained production in light of the experience of adjacent wells and the availability of, and premises for (e.g., proof of drainage), Board orders to compel sharing of pipeline and processing plant space.

What continued this lease? The interpretation of the shut-in clause

The shut-in clause of this lease posed an interesting interpretive issue that does not seem to have been taken by

Justice Romaine. As drafted, this shut in clause does two quite separate things. First, it provides that a well is deemed to be a producing well provided that there is a lack of or an unprofitable market. It is the deeming effect of the factual conditions that should extend the lease in accordance with the terms of the habendum. Second, and quite severable from the first as a matter of drafting, the clause provides an obligation to make a payment. There is nothing in the text that makes deeming conditional upon actual payment or deemed payment. On this line of reasoning, the failure to make a timely payment would not have been fatal on any construction of the terms of the lease or the proviso to the default clause; it would merely have triggered the main body of the default clause for there would have been a breach of an obligation. Given the space that the court accords to the plaintiff's late shut-in payment argument, the Court must have rejected this line of reasoning (the premise of the plaintiff's argument must have been that late payment was fatal) but does not offer reasons for doing so. This seems odd in light of Justice Romaine's preference (which I share, see my comment on the first *Durish* case at (1988), 63 Alta. L.R. (2d) 269)) for an approach that favours interpretation of each lease on its own terms rather than an application of presumptive rules of law.

Termination of the lease during the secondary term

Justice Romaine takes the view that there is something different about the secondary term of an oil and gas lease. Just what is the difference? According to Romaine, the difference lies in the fact that, by that time, the lessee will have made investment backed expectations and that, therefore, commercial reality demands that we treat the lessee with greater solicitude. The reasoning is unpersuasive. Conversion from the primary term to the secondary term is not the magic moment at which investment backed expectations arise, and, in any event, investment backed expectations alone will not suffice; the lessee must bring itself within the fours corners of a relevant estoppel doctrine. There are many cases in which such expectations have arisen during the primary term and yet the courts have still found the lease to have terminated. *Sohio v. Weyburn*, [1971] S.C.R. 81, aff'g 69 W.W.R. 680, is simply one case with a particularly dramatic set of facts. No; if we are going to find a difference, it must be a legal difference rather than a policy difference. And here we must at least think about just what the secondary term is; and to do that I believe that we need to think in terms of general legal categories, at least at the outset.

The lease in its secondary term is for an estate of an uncertain duration, most likely some form of determinable fee. The question that Romaine should have asked herself was: how do determinable fees come to an end? And the doctrinal answer is that they come to an end automatically without the need for the exercise of a right of re-entry: Anger and Honsberger, *Law of Real Property*, 2d ed. at para. 505.3. Justice Romaine might then have asked whether the proviso to the default clause was really intended to change that result and whether it could do so as a matter of law. Putting the question this way makes the issue clearer. The case that the lessee must meet, framed this way, is that the proviso to the default clause was actually intended to serve as an additional (fifth) proviso to the habendum *thereby* preventing automatic termination. For it is, after all, the habendum that governs duration and it is the habendum that tells us what estate we have. Justice Romaine never addressed this point and instead seems (at para. 135 *et seq.*) to accept the defendant's argument that somehow the lessee is entitled to the benefit of the proviso because it had a *duty* to produce if it could not avail itself of the terms of the shut-in clause. This too is unpersuasive and, with respect, Justice Romaine's reasoning on this point is confused.

Williston Wildcatters

On February 26 1952, Payne *et al.*, the predecessor in title to the current plaintiff, granted a png lease to the predecessor in title of the current defendants. The lease had a 10-year primary term continued "so long thereafter as the leased substances or any of them are produced from the said lands …". The third proviso to the habendum provided that:

> "…if at any time after the expiration of the said Ten (10) year term the leased substances are not being produced on the said lands and the Lessee is then engaged in drilling or working operations thereon, this lease shall remain in force so long as such operations are prosecuted and, if they result in the production of the leased substances or any of them, so long thereafter as the leased substances or any of them are produced from the said lands; provided that if drilling, working or production operations are interrupted or suspended as the result of any cause whatsoever beyond the Lessee's control, the time of such interruption or suspension shall not be counted against the Lessee, anything hereinbefore contained or implied to the contrary notwithstanding."

The lease also contained a standard default clause. The lessee had the 12-8 well drilled and producing by November 1955. Production continued thereafter but on a declining basis until, by December 1988, the then lessee was reporting to Saskatchewan Mineral Resources (SMR) monthly production of 0.6 m3 of oil and 1.6 m3 water. For each of the succeeding months of January, February and March the lessee reported identical production data. In January 1989, the flow line froze. Further freezing problems were encountered in December 1989 and January 1990

notwithstanding efforts in the fall of 1989 to install an underground storage tank that SMR subsequently forbade the use of. There was no production from February to July 1990. There was a road ban during March and April. Following a workover in July, production re-commenced August 1990 before ceasing for good in May 1991. In the meantime, Wildcatters, a farmee from the lessee, drilled a second well, the 11-8 well which was commenced May 20, 1991 and completed May 28 1991 with production commencing in June. A royalty cheque for this production was received by the plaintiff in August.

Under the terms of a royalty trust agreement of June 1955, Montreal Trust became the registered owner of the mines and minerals as a bare trustee for the beneficiaries under that trust. Royalties were payable to the plaintiff as trustee and all communication by the lessee was with the trustee. Under the terms of the trust deed the plaintiff exercised its powers and authorities under the lease upon direction from the unit holders. In February 1993 the plaintiff commenced this action seeking a declaration to the effect that the lease had terminated. Questions of accounting and quantification of losses and damage were reserved. There was also a cross claim by the farmees against the farmors alleging that if the lease were found to have terminated then the lessee/farmor would be in breach of its covenant to the effect that "it has complied with the terms of the lease … to the extent necessary to keep them *(sic)* in force".

Chief Justice Gerein at trial held that the lease had terminated and was not saved by estoppel. In Gerein's analysis there were two periods to consider during the secondary term: (1) January to March 1989 and (2) January to July 1990. For the first period, the identical production records, while suspicious, did provide some evidence of production and could not be rejected. Accordingly, the lease remained in force during this period. For the second period there was no production whatsoever and the lease could only be maintained in force by virtue of being engaged "in drilling or working operations" or if such operations were suspended by a cause beyond the lessee's control, all within the meaning of the third proviso.

While there was no standard definition of working operations, earlier decisions including *Cull* and *Crozet* supported the conclusion that working operations must be activities which are directed to bringing about the production of oil. With two exceptions, none of the lessee's activities could be so characterized including: removal of snow from the site, the hauling away of salt water, the acquisition and refurbishment of a service rig, the payment of taxes, the maintenance of the surface lease and correspondence and records relating to the lease. These activities could be categorized, respectively, as efforts to clean-up the site rather than to restore production, efforts undertaken as part of an overall business operation, and, simply, as administrative matters of a clerical nature that had nothing to do with production. The two exceptions were both attempts to thaw the flow line but these were isolated acts, widely spaced in time, pursued only briefly, and best described as minimal and futile and not a meaningful attempt to secure production.

Neither (following the Alberta Court of Appeal's decision in *Kinninmonth*) were there any matters that were beyond the lessee's control including the weather (nothing out of the ordinary for a Saskatchewan winter), road bans (either expected or avoidable by means of a permit) and the government's refusal to allow the lessee to use an underground storage tank (the lessee should have been familiar with the regulations and in any event the tank could have been readily replaced).

The lessee was unable to establish the requirements of estoppel by representation, estoppel by acquiescence, or proprietary estoppel. The argument of estoppel by representation failed because the actions of the plaintiffs in accepting royalty payments and in consenting to the drilling of a horizontal well (not in fact drilled) did not amount to a representation of fact relating to the validity of the lease. Neither was there an intention manifested that the lessee should rely upon such a representation and neither was there reliance. As to estoppel by acquiescence, while some of the five *probanda* from *Wilmott* v. *Barber* could be met, the lessee could not establish that the plaintiff must have been aware of its legal rights. This was the case even though one of the beneficiaries of the trust was sophisticated in the ways of the industry and the rules pertaining to oil and gas leases. That beneficiary was on notice that the 12-8 well was shut-in but that information was not itself conclusive without on-the-ground knowledge of just what (if any) working operations were being conducted and that was knowledge that only the lessee had. The plaintiffs had no obligation to seek out and acquire such information. Finally, there was no encouragement given to the drilling of the 11-8 well.

The authorities on proprietary estoppel were all distinguishable on the grounds that there was no underlying legal relationship between the parties or some form of understanding in relation to the work undertaken. Similarly, the common knowledge shared in proprietary estoppel cases was not present here. The default clause was not triggered on these facts and the lessee was not entitled to notice before the lease could terminate. As to the cross claim, there was a breach of the farmor's covenant and the farmees were entitled to recover.

The court of appeal affirmed. The trial judge had correctly stated the relevant law and tests for estoppel. Insofar as

estoppel arguments raised mixed questions of fact and law an appellate court must not interfere with conclusions depending upon findings of fact unless there is a palpable or overriding error. In considering the meaning of “working operations” the trial court correctly dismissed those activities unrelated to production of oil as well as other activities that did not demonstrate due diligence.

Several points perhaps deserve further comment. First, the plaintiff trustee does not seem to have argued that the minimal production during or even before the first period was inadequate to maintain the lease on the grounds that it was uneconomic: as to which see Bartlett, “The Effect of Low Oil and Gas Prices on Freehold Oil and Gas Leases: A Problem of Interpretation” (1991), 29 Alta. L. Rev. 1. Second, the case does raise an interesting question as to whose knowledge is relevant in the context of an estoppel by acquiescence argument, is it the knowledge of the bare trustee or the knowledge of the beneficiaries? The court does not discuss the question explicitly but the court spends considerable space exploring the state of knowledge of one of the unit holders who is at least two steps removed from the actual lessor. Third, and as to the cross claim, Gerein quickly found that the farmees were entitled to succeed. While this finding seems correct surely Gerein goes too far when he says that the farmor “covenanted that it held a valid lease”. The farmor did not so covenant and in fact stated, as the farmor typically does, that it did not warrant title. The point might have deserved a little more consideration. After all, what does “compliance with the terms of a lease” (the language of the covenant) mean when production and working operations constitute options and not obligation?

Still outstanding are some interesting accounting problems. In that context one can expect Justice Gerein to regret his somewhat flippant comment in the context of the estoppel arguments (and apparently accepted by the Court of Appeal at para. 33) to the effect that: “Even if there was no valid lease the plaintiff was entitled to be paid royalties based on the oil produced.” If the lease has terminated then the production is unlawful and the lessor is surely entitled to an accounting of all production, subject only to the availability of equitable arguments such as those found to be persuasive in *Weyburn* v. *Sohio*.

Board Shut-in Decision Questioned

In a note that primarily dealt with the EUB’s Surmont decision (EUB 2000-22), *Resources* #73, Winter 2001 at 10, I also referred to the EUB’s decision in Goodwell Petroleum Corporation (EUB 2000-21) in which the EUB, on the application of Goodwell which owned the petroleum and natural gas rights, ordered certain AEC bitumen wells shut-in on conservation grounds and on the basis that they were producing significant volumes of gas-cap gas. The Court of Appeal [2002] A.B.C.A. 251 has granted AEC’s application for leave to appeal on the following grounds: (1) Did the Board err in law or jurisdiction in determining that AEC’s right to produce leased substances under its oil sands leases does not include any production of initial gas-cap gas? (2) Did the Board err in law or jurisdiction in shutting-in the wells until such time as AEC has the “the full rights to produce” the gas-cap gas and by encouraging it to enter into a production and cost sharing agreement? If the matter proceeds it may provide the occasion for the Court to offer some guidance on the scope of the *Borys* decision and the duties, if any, owed by the petroleum or bitumen owner to the owner of the gas cap especially in light of the broad dicta of the Court of Appeal in the *Anderson* decision [2002] A.B.C.A. 162 and discussed in this newsletter at *Resources* #78 at 13.

The Court of Appeal Reverses Sarg Oils: Collateral Attack Rejected, the ERCB\EUB Can Abandon for the Account of the Well Licence Transferor

In *ERCB* v. *Sarg* (1998), 236 A.R. 298, 67 Alta. L.R. 296 (Q.B.) at trial, Justice Lutz had accepted Sarg’s argument that it was entitled to resist the ERCB’s attempt to recover the abandonment costs for a well that had once been owned by Sarg and for which it was still the licensee. Lutz’s position was that, but for a change in ERCB policy, Sarg would have been able to transfer its well licence responsibilities to a purchaser at the same time as it transferred title to the property, and, furthermore, that the manner in which the ERCB effected its change in policy was flawed and therefore not opposable against Sarg. I offered a short critique of this decision in both *Resources* #64, Fall 1998 at 4 and in more extended form in (2000), 33 Alta. L. Rev 294 at 302-307 primarily on the grounds that the court should not have permitted this form of collateral attack.

The Court of Appeal has reversed [2002] A.B.C.A. 174 noting that an application of *Maybrun Mines* (1998), 158 D.L.R. (4th) 193 (S.C.C.) “compels the conclusion that the legislature intended the Board, rather than the courts, to deal with the matters at issue here.” The Court found that Lutz’s decision placed too much emphasis on the fairness of the Board’s procedure. The Court also found that the Board was entitled to include in its invoice all of the costs incurred in effecting the abandonment, not just its out-of-pocket expenses. The Court did however agree with Lutz that Sarg was not entitled to recover its abandonment costs from the lawyer who had advised it on the sale of the subject property. The Court declined to interfere with Lutz’s finding of no

negligence and expressly endorsed his conclusion that the lawyer could hardly be liable when the evidence suggested that there was no effective way of affording the vendor protection against the decision of the ERCB not to approve a well licence transfer. The court similarly dismissed an argument that the solicitor for the purchaser had breached certain trust conditions.

Amendment to Definition of Royalty in Aboriginal Land Claim Agreement Settles Appeal

In *Sahtu Secretariat Inc.* v. *Canada* (1999), 12 F.T.R. 30 and discussed in *Resources* #66, Spring 1999 at 7, the Federal Court trial division had held that certain sums payable to Canada by Imperial Oil under the terms of the Norman Wells Agreement of 1944 were subject to the revenue sharing provisions of the Sahtu Dene and Metis Comprehensive Land Claim Agreement. Canada appealed and the parties entered into a settlement agreement the terms of which saw a significant payment by Canada and the definition of "royalty" in the agreement amended retroactively to exclude the payments in question. The amendment fundamentally changed the factual basis for the trial decision and accordingly the respondents agreed to an order allowing the appeal: [2002] F.C.A. 315.

Royalty Tax Credit Legislation

CNG held two Crown oil sands leases for the Lindbergh area. CNG had followed the practice of using its provincial Crown royalty payment to claim a credit for the purposes of its liability for Alberta Corporate Tax, all under the terms of the Alberta Royalty Tax Credit (ARTC) program. The pre-1997 legislation made eligible for the program, amounts "in respect of a royalty receivable or payable to the Crown … under a lease or licence granting petroleum rights, natural gas rights or petroleum and natural gas rights; or is in respect of a royalty receivable or payable to the Crown in right of Alberta pursuant to the Oil Sands Regulation, 1984 … in respect of a prescribed lease." However, in fact, CNG had been paying the Lindbergh royalty pursuant to a special agreement, the Alberta Lindbergh Crown Agreement rather than pursuant to the Regulations. Consequently, when the Provincial Treasurer carried out a reassessment of CNG's tax liability he disallowed CNG's ARTC claim. CNG filed a notice of appeal in June 1996 and the Treasurer, following a hearing, rejected the appeal by notice of March 21, 1997. The precise dates were potentially important. The Alberta Legislature amended the relevant legislation in June 1997. The Bill received third and final reading on June 11, 1997 but came into force on June 18, 1997 and provided, inter alia, that "for greater certainty, a qualified royalty … does not include any royalty under an agreement … granting rights to oil sands". The Bill went on to provide that this applied to "taxation years beginning after December 31, 1980." CNG sought to question the retroactive application of the Act relying on three rules of statutory interpretation: (1) the presumption against retroactivity of legislation, (2) the presumption against interference with vested rights, and (3) the presumption against interference with pending litigation. CNG placed most emphasis on the last point.

The Court of Appeal rejected all three arguments: *CNG Producing Company* v. *Alberta (Provincial Treasurer)*, [2002] A.B.C.A. 207. While the Court noted that it had received no argument as to whether CNG had obtained a vested right to the ARTC before the amendment came into force, the Court concluded that CNG had "no property right and no contractual right to the ARTC" apparently on the basis that no court or tribunal had ruled that CNG was so entitled. However, even if CNG had vested rights the presumption against interference had been rebutted in this case. Similarly, so had the presumption against interference with pending litigation. There is no rule of law that requires the legislature to specifically mention pending litigation in order to rebut the presumption. The central inquiry is always the intention of the legislature and in this case the unambiguous language of the amendment indicated that the legislation was intended to apply retroactively.

An Implied Right to Reasons

While the Surface Rights Board of Alberta is subject to the requirement of the *Administrative Procedures Act* that it provide reasons for its decisions, there is no similar statutory entitlement to reasons under the surface rights provisions of the *Petroleum Natural Gas Act* of British Columbia. However, while previous cases on that regime have suggested that there is no common law right to reasons, Justice Loo in *CNRL* v. *BC (Mediation and Arbitration Board)*, [2002] B.C.S.C. 1543 has chosen to emphasise that a duty to give reasons may be found in a particular case as a necessary implication of the overall regime, or on the basis that a failure to justify a decision in a particular case may be patently unreasonable. In the present case, the Board had made a global award on an application to arbitrate the difference between the parties on an attempted renegotiation of lease compensation. The award apparently included an amount to represent possible future losses of cattle due to unauthorized access by hunters. The award was justified on the grounds that there was a causal connection between the failure to lock gates and post appropriate signs and unauthorized hunting. Justice Loo held that while an award for cattle losses might be justifiable the Board had a duty to separate and justify its awards both because there was a statutory right of appeal and because the Board's ongoing duty to review its past decisions on compensation required that it must know how past decisions had allocated values. A global award is justified where the evidence discloses an established rate or pattern of compensation but that was not this case.

Quantum Meruit and Contract

In *Resources* #78, Spring 2002 at 10, I commented on the decision in *Pure Energy Marketing Ltd.* v. *Ramarro Resources Inc.*, [2002] A.J. 578, A.B.Q.B. 342 in which the court had relied upon the old rule that there can be no recovery under a *quantum meruit* claim where there is a contract that covers the same ground. This is clearly good law but in *Silver Springs Oil Recovery Inc.* v. *Saskatchewan Government Growth Fund II Ltd.*, [2002] S.K.Q.B. 428 Justice Foley shows how additional requests of the contracting party may allow *quantum meruit* claims for those additional responsibilities. In that case, Silver Springs had been retained to market a failing company with payment conditional upon a successful sale. The sale never materialized and the court denied Silver Springs main claim to compensation for time spent working on the sale. The court did however allow a smaller claim for time spent meeting other requests which were held to fall outside the contingency fee arrangement.

◆◆ Nigel Bankes is Professor of Law at the University of Calgary and is the Canadian Oil and Gas Law Reporter to the Rocky Mountain Mineral Law Foundation Newsletter.

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MFH 3330, University of Calgary, 2500 University Drive N.W., Calgary, AB T2N 1N4
Telephone: 403.220.3200 Facsimile: 403.282.6182 E-mail: cirl@ucalgary.ca
Website: www.cirl.ca

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