The explanatory notes reflect observations on the intention and scope of the provisions of the Operating Procedure. They have been included only to assist users in understanding the document, and are not intended to have any legal effect on the interpretation of the document. Although the Operating Procedure has been prepared as a service to industry, the onus is on users to ensure that the provisions of the document are appropriate for their circumstances. Users may wish to amend portions of the Operating Procedure to address their particular needs for a transaction, as identified in the annotations and in the Addendum at the end of the document.

Heading: The Operating Procedure will be attached to a Head Agreement. It will, as a minimum, describe the "Joint Lands," state the "Working Interests" and designate the "Operator". It will also include any special provisions negotiated by the Parties for such matters as an AMI.

Abandonment: i) Note the references to the salvage of material, the Regulations, Production Facilities and the reclamation of the applicable surface location. Abandonment obligations do not cease with the plugging of a well or the removal of a Production Facility. Surface rights that require remediation work could survive the mineral rights until reclamation certificates are obtained. The Regulations may also require responsibility for Environmental Liabilities to continue after issuance of a reclamation certificate. (See also Clause 1.14 and the associated annotations.)

ii) The reference to Production Facilities was added in the 2007 document. It is unlikely that a Production Facility of significance would be Abandoned under this document. It is far more likely that such a facility would then be subject to a separate CO&O agreement, as Clause 14.02 prescribes a process whereby a Production Facility meeting certain requirements ceases to be subject to this document and requires a CO&O agreement.

Accounting Procedure: The Accounting Procedure is an attachment to the Operating Procedure, with the combined document being a Schedule.

AFE: i) The nature of the financial authority granted by an approved AFE is considered in the notes on Subclause 3.01C. The Operation is a condition of the approval, but the Operator does have some latitude to deviate from the described Operation. This is limited, and would probably apply to only minor changes or those dictated by necessity during the Operation. The Operator should obtain consent of the other Parties before making any significant changes. Otherwise, there is a risk that a Party could successfully argue that its previous election was void or limited, as it did not pertain to the Operation that was conducted. See, for example, Passburg Petroleums v. San Antonio Explorations Ltd. and D. W. Axford & Associates Ltd., [1988] 2 W.W.R. 645 (Alta. Q.B.), in which the Court briefly considered the overrun issue and the Renaissance case (See the notes on Subclause 3.01C) in the context of the 1981 document. The Passburg case turned on the fact that the Operator drilled a directional well because of surface restrictions after obtaining approval to drill what the other parties reasonably believed to be a conventional vertical well. On the facts, the Court determined that there was no disclosure to the non-operators of the intention to drill directionally and that they did not agree to participate in a directionally drilled well, such that they were not responsible for the incremental costs. (See also Prairie Pacific Energy Corp. v. Scurry Rainbow Oil Ltd. (1994), 147A.R. 260 (Alta. Q.B.), in which the defendant presented an AFE for a recompletion program in a specific horizon under a pre-CAPL agreement and proceeded to conduct unauthorized perforations that were exploratory in nature, after which the well had water problems. The Court did not find the defendant liable for the water problems, but determined that the plaintiff was not required to pay for the cost of the operation.)

ii) An AFE must include sufficient detail for a Party to appreciate the nature and scope of the Operation and the estimated costs of its various phases. If a Party is not provided with the information it reasonably requires to make an informed decision or the supplied information is misleading, elections might be voidable. It is the better practice to provide all material information that is reasonably anticipated to influence the decision, recognizing that this would not extend to interpretations obtained for the issuing Party's account and any economic analyses.

iii) The requirement to identify the formation in which a Horizontal Leg is proposed is addressed expressly as of the 2015 document, when it was inherent in the more general, "its nature" reference in the prior documents. There may be circumstances, though, in which there is a thick target formation for which it will be important to be more precise about the geologic target for a Horizontal Leg. There are areas, for example, in which the Montney is very thick, and includes specific identified member subsets, such as the Upper Montney, Middle Montney and Lower Montney. It may be appropriate to modify the definition for those circumstances by adding something such as, *"(or the applicable specific member of that formation in circumstances in which a formation has discrete members that could potentially be a separate geologic target for a Horizontal Leg)"* after "Horizontal Leg will be drilled". This would ensure that the Operation in which participation is requested is clear when presenting a Horizontal Well for approval.

iv) The reference "in whole or in part" for drilling recognizes that activities such as a Deepening or a Sidetracking are subsets of drilling. (See also the definitions of Drilling Costs, Deepening and Sidetracking.)

v) The proposed coordinates of a well are to be specified. This alerts the Parties that the well might be subject to a production penalty under the Regulations if the well is being drilled outside a prescribed target area. It also ties the location to any joint seismic data, preferably by noting the applicable shot-point. It is the better practice to include a survey plan for a Horizontal Well and any other well with a material deviation, recognizing that Subclauses 3.01D, 3.01E and 10.02H provide Operators with some flexibility to modify a Horizontal Well to reflect real time data.

vi) Paragraph (a) requires the disclosure of downhole coordinates if there is expected to be a material difference from the surface coordinates. Intentionally changing the location so that the well attracts an off-target production penalty under the Regulations would be a good example of a situation that would meet that test. Otherwise, the materiality test is context dependent, based on the impact of the deviated location on the evaluation of the particular prospect. There are situations in which a relatively small difference in location could have a large impact on the evaluation of the play (e.g., a small reef play). It is not feasible to define a prescriptive materiality threshold. (See Subclauses 3.01E and 10.02H.)

vii) A reference to Completion and Equipping costs in a drilling AFE is subject to the Casing Point election and Independent Operations processes.

viii) Parties that anticipate significant Drilling Costs for pre-Spud activities such as environmental studies or community and stakeholder consultation will sometimes choose to address these costs in an interim AFE that will be integrated into the AFE for the well in due course. A Party that does not approve the interim AFE for these activities will see those costs included in the AFE for the well in due course. A Party that approved the interim AFE would reserve the right to elect not to participate in the remainder of the drilling activity once it is presented for approval. It would see its cost recovery based on the costs it did not contribute for the well, although clear internal communication would be required to ensure that the records were set up properly. There may be circumstances in which the costs and risks of these early-stage activities are so significant that the Parties negotiate a specific provision in their Agreement or at the time to address this work. This would typically see a non-participant in the initial work having an obligation to pay some multiple of its share of those costs as a condition to its participation in the resultant well.

Affiliate: i) The updated definition was introduced in the 2007 document. It is very similar to the definition in the 1993 CAPL Assignment Procedure.

ii) The partnership reference recognizes that some companies have created partnerships comprised only of corporations that are Affiliates, for tax and other business reasons. This ensures that the corporation acting as "managing partner" and its corporate Affiliates are regarded as Affiliates of the partnership and *vice versa*. If it is comprised of other entities, the definition might be modified for the specific situation.

iii) The trust references were added because of royalty trusts.

Business Day: Parties located outside Alberta will often modify this definition, the time zone (Paragraph 1.02(h)) and the Clause 1.06 jurisdiction.

Commenced: This definition was introduced in the 2007 document. It brings greater certainty to such references as "commenced" or "commencement" in the document (versus any application to a freehold lease held as a Title Document). This has sometimes been an issue, particularly for wells. "Commenced" is equated to Spudding for drilling a new well, as in Subclause 701(a) of the 1981 document. This is subject to Force Majeure, where this includes the inability to obtain licences or approvals required under the Regulations. Increasing the general Commencement period to 120 days under Clauses 7.01 and 10.03 in the 2007 document largely mitigated any negative impact of this definition.

The Spud date will generally be appropriate for drilling because of the increase to the Commencement period. Surface access issues for some remote areas or areas expected to involve sensitive stakeholder consultation might warrant amendments. The onus is on users to recognize and address those exceptions or to address them at the time for any particular well. The simplest way to address a special circumstance is to extend the Commencement period by another 60-120 days in Clauses 7.01 and 10.03, but some Parties might choose to use the initiation of road or wellsite construction. Parties should consider identifying this issue in their precedent election sheet as a potential amendment, to mitigate the risk that it may be missed when preparing an agreement for a challenging operating area.

Commercial Quantities: i) Production in "Commercial Quantities" or "Paying Quantities" does not lend itself to a precise determination, largely because of the "anticipated" references throughout the definitions. It is implicit, though, that there must be a reasonable basis to determine that an item is anticipated. A dispute on either of these definitions can potentially ultimately be resolved through arbitration under Clause 21.03.

ii) The generic "hydrocarbon substances" reference covers the full spectrum of Petroleum Substances and Outside Substances. It is used because the well productive in Commercial Quantities is not necessarily on the Joint Lands. (See, for example, the definition of Development Well.)

iii) It might be difficult to argue that a discovery is in Commercial Quantities if the well cannot be produced for five years because of a shortage of facilities or a queue for transportation service. Special considerations could apply, though, to high-risk, high-reward Operations in remote areas.

iv) Note the reference to burdens payable for the Joint Account. This ensures that the Parties are on an equal footing for the determination. Otherwise, a well could be a discovery in Commercial Quantities for only some of the Parties.

Completion: i) See the annotations on "Equipping" for the rationale for the exclusion of artificial lift equipment.

ii) The definition has been modified as of the 2015 document. It reflects some of the comments of the Court in Solara Exploration Ltd. v. Richmount Petroleum Ltd., [2009] 2. W.W.R. 530 (Alta. Q.B.) about potential ambiguity in the traditional provision, and is clearer about the handling of surface equipment required to be on the site temporarily to conduct a Completion program. The specific reference to required temporary surface equipment was introduced in the 2015 document in the context of shale testing programs. These costs should be identified as a line item on the AFE in accordance with the expectations in that definition.

Deepen: Subclause 3.01D, 3.01E and 10.02H provide an Operator with some discretion to extend a Horizontal Well when warranted by results. Insofar as the Operator continues to drill within that authority or any other authority granted to it (i.e., AFE), the incremental drilling is not a Deepening.

Development Well: i) For context, the distances in the 1971, 1974, 1981, 1990 and 2007 documents were also two miles (3.2km).

ii) The status of a well as a Development or Exploratory Well is determined as of issuance of the applicable AFE or Operation Notice, so that outcomes are clear at the time of the election. This clarification was introduced in the 2007 document. The reference to an AFE is included because of the possibility that the triggering event could be a Casing Point election under Article 9.00. The status of the well may change over time relative to the Participating Parties (i.e., Clause 10.08 Recompletion of an uphole formation).

Paragraph (a) was introduced in the 2007 document. A "tight hole" owned by some subset of the Parties is generally ignored for the determination, to reflect the incremental risk they incurred. This is subject to two qualifications. The "tight hole" is factored in if all Parties have access to the data under this Agreement or another agreement or if each Party not then having access to the information has access in due course under Clause 10.19. The latter is included because that Party will generally be able to defer its election until after it receives that well information.

iii) The proviso in Paragraph (b) was introduced in a narrower form in the 1990 document because of the increased stratification of rights. If the Joint Lands under that document only include rights to the base of the Cardium and the only productive interval within 3.2km (two miles) is the deeper Nisku, the well is an Exploratory Well thereunder. Similarly, if the productivity pertained to oil in the X formation when the Joint Lands only include natural gas, the condition would not be met. A Party could not use the shallower exploratory designation (e.g., Cardium) under the 1990 document if it had the right to exploit the deeper development horizon (e.g., Nisku) held as Joint Lands.

The qualification was expanded in the 2007 document to link regional productivity to the formations penetrated by the well in all circumstances. Using the example above, the Cardium well would be deemed to be a Development Well under the 1990 document if the Joint Lands included the Nisku. The same well would be an Exploratory Well hereunder, as there is no regional productivity in the drilled formations. The definition of Spacing Unit would cause the well status to be modified accordingly if the Proposing Party were to propose to Deepen to the Nisku. The Receiving Parties would presumably also question the integrity of the Operation Notice if the Proposing Party presented the well as a Cardium well, but licenced it to the Nisku.

Well information from offsetting wells that are (or have been) producing in Commercial Quantities will often reduce the risk of testing a shallower (but non-producing) zone. That will not always be the case. Information from a deep well may confirm there is a high risk in testing a shallow objective.

While many shallow tests will evaluate exploratory objectives, it is inappropriate to eliminate the deeming mechanism entirely because data from the offsetting well may significantly reduce the risk. The elimination of the deeming mechanism for the shallower horizons would also create serious problems for the dual well scenario (Clause 10.05), as the exploratory portion of the well could overlie the development portion. The proviso is a compromise. It attempts to minimize the arbitrariness of the distance test by limiting the examination of productive intervals in offsetting wells to formations and substances being evaluated by the well, while including protections against abuse.

iv) The existing well does not need to be producing in Commercial Quantities. It is sufficient if it is (or was) capable of it. (The reference for the pre-existing well is to hydrocarbons rather than Petroleum Substances, as the pre-existing well does not need to be subject to theTitle Documents.)

v) The definition includes a simple distance test to determine if a Horizontal Well or a vertical well near a neighbouring Horizontal Well is a Development Well. The entirety of a Horizontal Well, including any and all legs thereof, is considered a single "well" for the purposes of this determination. The Parties should amend the Operating Procedure if they wish to use any other test for the determination of a "Development Well".

The location of the new well could change during drilling. This may be due to factors beyond the Operator's reasonable control (i.e., foothills drilling) or it could be intentional. An intentional change could cause elections to be voidable. (See Subclauses 3.01D and E and 10.02 H and the annotations on those Subclauses, the definition of AFE and Clause 10.07.)

vi) The well classifications dictated by the distance test will often be inconsistent with the technically based "Lahee" definitions used by regulators and technical personnel, though. (See, for example, the well descriptions in AER Directive 56.) The modifications in the 2007 document mitigated the problem somewhat for shallow exploratory targets. Technical personnel need to understand the potential Article 10.00 implications of alternate drilling locations when selecting their preferred drilling location, as the difference between the cost recovery associated with a Development Well and an Exploratory Well will typically be significant (usually at least 200%). Clause 10.05 also allows a well to be in part Development and in part Exploratory.

vii) The Parties might prefer to amend the well definitions from the distance test to the "Lahee" definitions in some circumstances. This is particularly the case for high-risk, high-reward areas or small reef plays. A 1.6km threshold, for example, may be preferred when working in an area in which the prospects might have a small areal extent, such as independent reefs.

Drilling Costs: i) Operators place much more emphasis on community and stakeholder consultation than had been the case, largely because of regulatory requirements (e.g., Alberta's Directive-56 requirements) and evolving obligations for First Nations' traditional land areas and activities "north of 60". These costs can be significant, and are included in the cost of a project. (See also the definition of Equipping and Clause 3.09.)

ii) Note the reference to roads. The Operator has a general obligation to conduct an Operation in accordance with good oilfield practice, such that it is to be conducted in a cost effective manner. An approved well AFE does not provide a blanket authorization to build a road that largely duplicates an existing road or a road that greatly exceeds the specifications that are reasonably appropriate in the circumstances.

iii) The handling of Abandonment costs is consistent with the PASC Accounting Procedure, subject to the special cost allocations under Clause 9.04 and Subclauses 10.06E and 10.08E between the Parties that participated in drilling the well and the Participating Parties in further Operations.

iv) Deepening and Sidetracking are subsets of the broader drilling reference.

v) A Well Pad might be used for only wells on the Joint Lands or for a combination of Joint Lands and other lands. The costs for acquiring the applicable surface rights, the preparation of the well site and the construction or use of applicable access roads are to be allocated to the wells using that Well Pad. In the absence of agreement by the Parties/applicable owners at the time or any separate agreement relating to the ownership and operation of that Well Pad, the default allocation is on a well count basis to the wells for which that Well Pad was initially constructed and that are reasonably expected to be drilled over the first 24 months, using the principles outlined in any then current PASC Accounting Guidelines on the Distribution of Shared Pad Costs. The owners would preferably enter into a specific pad sharing agreement to address the broad range of issues associated with Well Pads. (See also Subclause 10.04A and the related annotations.) In practice, the modest pad costs relative to the forecast drilling costs will often see pad costs allocated only to the initial year's drilling program if wells are drilled on each applicable mineral interest block.

Earning Agreement: i) This definition is used in Article 24.00. The ROFR exemption in Paragraph 24.02(d) generally applies if the net hectares of Joint Lands being disposed of under a transaction other than an Earning Agreement represent less than 10% of the total net hectares in the transaction. Paragraph 24.02(e) was introduced in the 2007 document, and provides that the exemption threshold for a disposition under an Earning

Agreement is 35%. This will see fewer ROFRs applying to farmout type arrangements. Optional Paragraph 24.02(f) also provides Parties with the ability to exclude all Earning Agreements from the scope of a ROFR.

ii) A seismic review option is within the scope of this definition. Notwithstanding that there are several potential elections, the transaction is ultimately one in which the potential assignee has the option to acquire a Working Interest in return for a prescribed work program.

iii) A transaction is not an Earning Agreement if part of the consideration is cash (ignoring land rentals and seismic access fees) or an exchange of another property. This minimizes the potential to try to circumvent a ROFR by structuring A&D transactions with a minor farmout component.

Environmental Liabilities: This definition was introduced in the 2007 document, and reflects the increased emphasis on this area. It largely mirrors the definition in the 2000 CAPL Property Transfer Procedure.

Equipping: i) The corresponding definitions in the 1974 and 1981 documents were similar in intention to this definition. However, it was not sufficiently clear if and how they would apply to equipment serving more than one well. The introduction of the Production Facility concept in the 1990 document clarified the scope of the definition by linking it to equipment that serves a single Completed well.

ii) The scope of a particular Equipping Operation may be limited to a particular subset of the listed items. A tie-in, for example, is an Equipping, assuming it meets the other requirements in the definition.

iii) A pump or other artificial lift equipment falls within the scope of Equipping, even if the equipment is in the well. The function of the equipment should determine its classification, not its physical placement. The investment risk is also lower than the components of Completion.

iv) The inclusion of community and stakeholder consultation and the acquisition of required regulatory approvals and surface access reflects the increased complexity and costs associated with these matters in recent years.

Extraordinary Damages: i) This definition is generally consistent with the handling of this issue in modern international agreements (i.e., the definition of “Consequential Loss” in the AIPN Operating Agreement). The handling of this issue in the 1990 document was limited to a loss or delay in production and associated damages under Clause 401 of that document.

ii) It is tempting to assume that a Court would make such an award in the absence of this definition and Clause 4.04. The case law on damages would apply, though. This includes limits, such as a “remoteness” test, on the range of damages that a Court could award for any such breach.

iii) The exception for breaches of Article 18.00 was included because an unqualified version of this definition would, in essence, eliminate all consequences for breach of the confidentiality obligations.

iv) Damages from loss of well control and (as of the 2015 document) other inadvertent releases during Operations fall within the scope of the definition, and this addresses the area of greatest environmental risk in practice. An Operator also remains free to argue that other types of environmental loss fall within the more generic exclusion in (i) or that they are otherwise beyond the scope of the Court’s ability to award damages because of legal principles respecting “causation”, “foreseeability” and “remoteness”. It may be appropriate to modify the provision to add Environmental Liabilities more generally, if the risks to an Operator make the assumption of the responsibilities unattractive. This could be the case in a frontier type high-risk, high-reward context. It might also be considered for a CO&O Agreement for a sour gas facility, given the low probability that any major gathering system or gas plant would be managed under the CAPL document.

v) This definition must be read in conjunction with Clause 4.04. The limitation in that Clause ultimately does not expose an injured Party to third party damage claims of this type that may be awarded by a Court. It precludes the injured Party from trying to recover these types of damages respecting its own interest. It does not eliminate the obligation of the Party causing the loss to indemnify the injured Party against third party claims suffered by it.

vi) Assume that the Operator has sole responsibility for a loss. How do the Parties determine what portion (if any) of a damage award is attributable to Extraordinary Damages and has to be netted out? The Parties to any lawsuit will have to be cognizant of this liability exclusion and ask a Court to differentiate between the different heads of damages in any award of damages. Practically, this will always be the case, as the Party defending the action will raise early and often the fact that there are excluded heads of liability. If there remains confusion about the constituents of a Court awarded damage claim, the Parties may avail themselves of the “advice and direction” mechanism under the Rules of Court whereby the judge might clarify the damage award. The Parties could also address this if they were resolving a claim through arbitration.

Facility Fees: i) This definition is used only in the contexts of Clause 6.02 (costs in managing a Non-Taking Party’s production) and the cost recovery processes in Clauses 10.07 and 10.13 for Independent Operations.

ii) Paragraph (b) is largely derived from Subclause 10.13l and Clauses 14.04 and 14.08. It avoids the negotiation of the details of a formula, such as JP-95 or JP-05, when the Agreement is negotiated. The Party is permitted to charge the fee that it would have been charged if it were not already an owner of the relevant facilities. Why include this sort of deduction? A Party can deduct fees paid to third parties under Paragraph (a), which would probably be based on the “Jumping Pound” principles. It would be inconsistent to deny it a similar return on owned facilities for handling a Non-Participating Party’s volumes, especially since it may be forgoing third party revenues otherwise being paid to it for other volumes.

iii) The reference to operating cost and return on capital components is included to be clear that a capital component may be included in the fee.

iv) The JP-05 “methodology” reference in Subparagraph (b)(iii) is somewhat problematic because of its uncertainty. However, certainty on the calculation of the capital base would be required to be able to do this. This information is unlikely to be known at the time of the Agreement, and, in any event, is not provided under the JP-05 formula without detailed front end calculations. There may be circumstances, though, in which it is appropriate to negotiate a specific fee for use of a Party’s facility in the context of a particular Independent Operation, such as *“a capital rate of _____/10^3m^3, plus the actual cost of operating experienced by the operator of the facility”*. Alignment of expectations in this area at the time of an Independent Operation through a separate agreement could prevent subsequent disputes on the issue, so Subparagraph (b)(i) has been included to encourage the Parties to complete specific agreements on this issue on an Operation or project basis.

Facility Usage: Facility Usage is the use of facilities not included within “Equipping Costs” or under Clauses 10.13 and 10.14 to increase the value of production of a Non-Taking Party or from Independent Wells (e.g., processing of gas) and to deliver it to market. It excludes any adjustments for transportation costs required to determine the Market Price, to avoid a double recovery. This definition is linked to the Facility Fees definition.

First Point of Measurement: In essence, this is typically the point at which production volumes are measured under the Title Documents/Regulations. It is not feasible to take production before that point.

That is a very sweeping generalization, though. The production handling infrastructure is more complicated than a simple wellsite handling in many cases. It is possible, for example, for a phase one handling on site that separates gas (i.e., First Point of Measurement for that gas is on the well site). The emulsion would then be trucked to another phase two handling facility that handles production from a number of wells. The emulsion from each applicable individual well would be sampled for composition at the phase two handling facility, with the production then being combined with production from other wells for separation into distinct product/waste streams. Those streams would then be allocated back to the individual wells based on the composition samples that had been taken before handling at the phase two facility.

Force Majeure: i) This definition is an “unable to prevent” type of provision, rather than “a failure to perform as a consequence” provision. (See the annotations on Clause 16.01 about Atcor Ltd. v. Continental Energy Marketing Ltd., [1994] A.J. No. 715 (Alta. Q.B.).)

ii) This definition does not apply to events that a Party could have prevented with the exercise of reasonable diligence at a cost that is not unreasonable. Assume, for example, that a Party that intended to drill a critical sour gas well near a populated area chose to delay its applications to regulators until 45 days prior to the anticipated Spud date. Should that Party be able to rely on the Force Majeure provision if the well is not Commenced at the required time because of the resultant delay in obtaining regulatory approval?

The qualification about a cost that is not “unreasonable” reflects the practical fact that most things are possible at a cost. A Party should not be required to incur expenditures that are unreasonable to protect against an unlimited range of possible (but remote) eventualities.

Gross Negligence or Wilful Misconduct: i) Many judicial considerations of the concept of "gross negligence" were in automobile cases in which an injured non-paying passenger had to demonstrate that the driver's conduct was "grossly negligent" ("gratuitous passenger cases"). As the driver's insurance would generally cover a successful claim, the distinction between simple and gross negligence may have been blurred in some of those cases in order to find for the passenger. As a result, Operators could have greater legal responsibility for their actions in the absence of this definition.

ii) This issue was considered in United Canso Oil & Gas Ltd. v. Washoe Northern, Inc. (1991), 121 A.R.1 (Alta. Q.B.) in the context of a non-CAPL oil and gas agreement that limited the responsibility of the "Managing Operator" to losses caused by its "gross negligence or wilful misconduct". The Court applied the reasoning in the "gratuitous passenger" case of McCulloch v. Murray, [1942] S.C.R. 141 (S.C.C.) to find gross negligence in the maintenance of the payout account. In essence, the Court found gross negligence to be "a very marked departure from the standards by which reasonable and competent companies in a like position... in charge of joint ventures or accounting should habitually govern themselves. This was a conscious indifference to the rights or welfare of United Canso and its predecessors."

The issue was considered more recently in the context of the 1990 document and loss of a mineral interest in Adeco Exploration Company Ltd. v. Hunt Oil Company of Canada Inc., [2008] A.J. No.836 (Alta. C.A.), affirming 2007 CarswellAlta 1953 (Alta.Q.B.). In making a finding of gross negligence in that case, the Court of Appeal cited phrases from prior cases, such as "very great negligence", "conscious wrongdoing", "a very marked departure" from the standard of care, "the character and the duration of the neglect to fulfil [the] duty, including the comparative ease or difficulty of discharging it" as "important, if not vital, factors in determining whether the fault (if any)….is so much more than merely ordinary neglect that it should be held to be a very great, or gross, negligence" and "conscious indifference". (See also Trident Exploration Corp. (Re), [2012] A.J. No. 639 (Alta. Q.B.), in which there was another finding of gross negligence of the Operator under the 1990 document with respect to a loss of mineral rights respecting a parcel contributed by another party under a non-cross-conveyed pooling agreement.)

The 2007 definition that did not include item (i) was considered in Bernum Petroleum Ltd. v. Birch Lake Energy Inc., 2014 CarswellAlta 1965 (Alta. Q.B.). It related to the manner in which the Operator conducted Operations on two wells drilled for the Joint Account. The Court referred to both the common law and this definition, and concluded that the determination of Gross Negligence or Wilful Misconduct is both fact and context specific. It recognized that there is significant risk in industry projects, that many things can go wrong when conducting Operations and that "…Often, decisions in the course of drilling must be made quickly without time for extended consultation or analysis." Two major factors that contributed to finding in favour of the Operator were, firstly, the Non-Operator's "failure to lead evidence on industry standards by which the actions of Bernum could be compared" and, secondly, that the Non-Operator did not object to the Operator's drilling program until well after the fact. Based on this case, Operators should ensure that they are clear about a proposed program, a Non-Operator should express any concern promptly in writing and the affected Parties should prepare for any litigation on the issue in the context of industry standards and the potential impact of a different approach on the outcomes.

iii) The definition was introduced in the 2007 document. Other than for the addition of item (i) in the 2015 document to align it more closely to the definition used in the PJVA CO&O Agreement, it is similar to the definition in the AIPN Operating Procedure used for international agreements. Some American agreements include an additional qualification to except "errors of judgment and mistakes by the persons mentioned above while they are exercising, in good faith, any function, authority or discretion conferred upon them under this Agreement". This was not included because of the belief that the general language in the provision provides that protection already.

iv) The ability to use the instructions of the Parties as a shield only exists if the act or omission constituting Gross Negligence or Wilful Misconduct was inherent in the instructions. Prudent instructions implemented in a manner that meets the Gross Negligence or Wilful Misconduct test should not allow an Operator to avoid sole liability.

v) International agreements typically qualify the Operator's liability provision so that Gross Negligence or Wilful Misconduct must be attributable to the Operator's "Senior Supervisory Personnel". Parties might consider applying that principle in certain operating environments in which the magnitude of potential loss is very high (i.e., certain high cost, critical sour gas areas, major shale projects, frontier operations, etc.). While international agreements typically define this at a high level in the Operator's organization, Parties considering this concept might link it to first line supervision.

Horizontal Leg and Horizontal Well: Horizontal Wells can be drilled in at least two ways. In some circumstances, a single wellbore is drilled, beginning vertically and then gradually veering at an increasing angle from vertical until the wellbore is continuing horizontally into or within a particular formation. In other circumstances, a single vertical wellbore is drilled to evaluate the various formations encountered, following which one or more Horizontal Legs may be kicked off from the vertical wellbore in an effort to obtain production from a particular formation or formations.

The definition of Horizontal Well encompasses both of these types of wells. However, it differentiates between them because certain provisions of the Article apply to these different types of Horizontal Wells in different ways.

Joint Account: The corresponding provision in earlier versions of the document had been "for the Joint Account".

Joint Lands: i) The Joint Lands include not only the lands held jointly at the effective date, but those additional rights that become subject to the Operating Procedure over time, such as AMI acquisitions. The Joint Lands are also limited to those of such rights that remain subject to the Title Documents at the relevant time, such that Joint Lands that revert to the lessor at expiry are no longer Joint Lands.

ii) The application of the segregation process under Article 13.00 has the effect of changing the characterization of certain jointly held rights from "Joint Lands" to lands held under a separate agreement, even though the rights continue to be held under the Title Documents.

Losses and Liabilities: i) This definition simplifies the liability and indemnification provisions in the document. (See Article 4.00 and Clause 10.18.)

ii) Note the phrase "whether contractual or tortious". If the contractual liability reference is not included, a Court might interpret the provision to apply only to tortious liability, particularly for third party losses. See Dominion Bridge Company Limited v. Toronto General Insurance Company (1963), 45 W.W.R. 125 (S.C.C.) and Canadian Indemnity Insurance Co. v. Andrews & George Co., [1953] 1 S.C.R.19 (S.C.C.) in an insurance context.

iii) The reference "(including that Party or any other Party)" clarifies that Losses and Liabilities apply to both third party claims and losses suffered directly by the Parties. See the Clause 4.01 annotations on Erehwon Exploration Ltd. v. Northstar Energy Corp., [1994] A.J. No. 916 (Alta.Q.B.).

iv) In the absence of the qualification at the end of this provision, legal costs to be recovered by the indemnified Party would be limited to costs on a party-party basis, as prescribed by the Alberta Rules of Court. This would usually be far less than the actual costs paid by a Party.

v) The definition is subject to the general legal duty of an injured Party to mitigate its losses. This may include, in part, a duty to notify the other Parties of the losses so that corrective measures can be taken at the earliest opportunity.

Market Price: i) This definition applies to the sale of a share of production of a defaulting Party or Non-Taking Party under Article 5.00 or 6.00 and the sale proceeds included in a cost recovery under Article 10.00 for Independent Operations.

ii) There is a wide variation in pricing for natural gas due to major process changes in the marketing of natural gas since the early 1990s. The marketing of natural gas prior to that time had largely been under sales arrangements that were linked to specific lands and reserves, such that there was generally a paper trail for any disposition of natural gas from a specific well. The sales process was revolutionized in the early 1990s. Natural gas was increasingly sold under a portfolio of corporate supply arrangements through which the selling party was delivering a specific volume to its purchaser at a delivery point, with security for performance by the selling party being by corporate guarantee or warranty.

The nature of these arrangements is that sales volumes are typically independent of the lands from which production is obtained. Selling parties routinely buy and sell incremental natural gas on a short-term basis in the context of these sales obligations. The introduction and evolution of index-based pricing in Alberta has also caused the natural gas sales market to be much more liquid than had previously been the case. These changes have also facilitated an active hedging market, in which some companies are routinely selling natural gas under physical and financial hedging arrangements. The net effect of these changes has been that new reserves based dedicated lands sales contracts are the exception, rather than the norm. There is a high potential for large variances in pricing, particularly during a period of price volatility.

The challenge is to include pricing mechanisms that protect against notional, discretionary allocations of the least favourable marketing arrangements in a Party's portfolio, while not creating inappropriate outcomes for a Party disposing of gas volumes. There were two alternative approaches that could have been taken on this issue-(a) the inclusion of a detailed, prescriptive pricing mechanism that specified what the price is; or (b) a more general mechanism that focused on what the price is not, by including process controls to limit attempts to use a price that is unreasonable. After reviewing this issue in the context of a potential index pricing model and industry's feedback on it, the second approach was used. This approach and the flexibility in the optional last sentence for a Party to use the weighted average sale price for its own sale volumes from the jurisdiction preserve the desired flexibility in the vast majority of cases, while addressing the problem of arbitrary pricing allocations.

iii) The onus is on an objecting Party to demonstrate that a sale price was unreasonable, having regard to market conditions at the time. This ensures that the selling Party is not required to investigate each sale opportunity to try to obtain the highest price available in the marketplace.

iv) The reference to transportation also addresses the volumetric adjustments forming part of the consideration for the transportation service from entry into the transportation system to the point of sale. These adjustments, for such items as fuel and measurement variance, effectively operate to reduce the volumes available for sale. The net effect is that the adjusted volume bears 100% of the cash component of the pipeline toll. This is distinct from the handling of transportation costs, if any, prior to the point of entry into the common carrier pipeline system. The transportation costs between the First Point of Measurement and that point of entry will often be handled under Facility Fees.

v) Parties are encouraged to negotiate a transaction specific marketing arrangement if gas volumes will be significant and the Non-Taking Party is anticipated to be in that situation for a sustained period. The use of an AECO pricing index may be particularly attractive for those arrangements.

Multiple Well Completion Program: This definition, the definitions of Multiple Well Drilling Program and Well Pad and the related content at the beginning of Clauses 5.04, 9.01, 10.19 and 12.01 and Subclauses 3.01B, 10.02A, 10.02B, 10.02F and 10.07A were added as of the 2015 document. These changes offer greater functionality if Parties negotiate a custom provision for the development of individual Well Pads through multiple well programs. These references will mitigate the need for custom changes in the Operating Procedure to address Well Pads and multiple well development programs by supplementing a broad potential range of outcomes negotiated specifically for any particular Agreement. It was not feasible to address the topic more specifically, given the lack of consensus on pad development approaches when the 2015 document was created.

Operating Costs: The updates introduced in the 2007 document link more directly to operation and maintenance under the Accounting Procedure.

Operation: i) Operations are activities that relate primarily to the exploration, development and exploitation of the Joint Lands. They will typically be field activities and other approved in-house technical and environmental type studies. Tasks of primarily an administrative or managerial nature, such as land administration, accounting and management, are not "Operations", notwithstanding that they are being conducted for the benefit of the Parties. This definition was introduced in the 2007 document and updated slightly with the addition of the "relates primarily to" phrase as of the 2015 document in light of some of the comments in the Adeco case referenced in more detail in the annotations on Clause 4.01. This does not alter the liability and indemnification references in the document because they are linked to the Operator's duties under the Agreement.

ii) Geophysical programs can fall within the scope of the Operating Procedure, even if they are conducted to evaluate lands in addition to the Joint Lands. This ensures, for example, that the accounting and liability processes are in place for those programs. However, the Operating Procedure does not handle the full range of issues associated with the management of seismic data, as noted in Clause 18.07 and the related annotations.

Operator: i) Clause 10.04 can see a Proposing Party operate an Independent Operation in which the Operator elects to participate, even if all of the Parties participate in that Operation. The rationale for this provision is explained in the annotations for that Clause.

ii) There may be circumstances in which the areas of functional expertise are such that the Parties may agree that different Parties will conduct different types of Operations. This is something that those Parties would need to address specifically in their own agreement.

Participating Interest: The Participating Interest relates to a Party's share of the cost of an Operation, rather than to its interest in the Joint Lands or other Joint Property. A Party's Participating Interest and Working Interest would be the same for a Joint Operation.

Party: i) A farmor with an ORR would be party to the Head Agreement for the farmout, but would not be a Party under the Operating Procedure, except to the extent, if any, expressly provided for therein. The CAPL Farmout & Royalty Procedure, for example, provides a status to a farmor holding a convertible ORR for: (a) additional wells on lands subject to a payout; and (b) dispositions where a ROFR applies. (See Clauses 6.06 and 12.02 of the CAPL Farmout & Royalty Procedure.)

ii) The Parties may sometimes choose to have a Party's Affiliate or another third party serve as Operator, even though it does not hold a Working Interest. This is typically accommodated through the contract operating authority in Paragraph 2.02A(g). However, a custom amendment would be required if the vision were that an Operator without any Working Interest were to be a recognized Party under the Operating Procedure.

Paying Quantities: See the annotations on the definition of Commercial Quantities. Costs respecting a drilled well are considered on a future basis. Completion Costs and Equipping Costs, for example, do not factor into the calculation on a well that has been Completed and Equipped.

Petroleum Substances: Petroleum Substances are limited to the substances granted under the Title Documents. The term does not apply to hydrocarbon substances not held under the Title Documents, such that generic references are used in any context that involves other rights.

Production Facility: i) A Production Facility is basically a minor facility owned exclusively by all or some of the Parties which is intended and designed to serve exclusively the Joint Lands, where the Parties have decided against the preparation of a separate CO&O agreement. The facility is beyond the scope of the Operating Procedure if those conditions are not met. (See also the annotations on Article 14.00.)

A facility initially intended to serve the Joint Lands, but designed with the intention of serving other lands, does not fall within the scope of the definition. Otherwise, a Party might attempt to argue that a pipeline initially serving only a joint well could be a Production Facility, even though it was obviously designed to handle much greater volumes of production. To include those facilities within the scope of the definition would be inconsistent with the stated objective of providing Parties with the flexibility to apply the Operating Procedure to minor facilities.

Parties are encouraged to use a Construction, Ownership and Operating Agreement using the applicable PJVA model for any facility of significance or for any Production Facility that subsequently handles material volumes of Outside Substances. The creation of the PJVA model CO&O Agreement has simplified the process of completing facility agreements significantly, such that this is much easier than had been the case when the Production Facility processes were introduced in the 1990 document. However, the provisions are still required because of the large number of minor, property specific facilities for which Parties determine that the effort to prepare and administer CO&O agreements is not warranted.

Clause 14.02 was introduced in the 2007 document to create an outcome in which any Party can require a CO&O agreement using the most recent PJVA CO&O form in certain circumstances. This is mostly linked to use of the Production Facility for Outside Substances, where continued application of this document is regarded as inappropriate by any Party. This would typically be where fees or operating costs associated with the use for Outside Substances are significant. The Parties retain the ability not to trigger that process, though, as there will be many circumstances in which the use for Outside Substances is so immaterial that the continued application of this document to the Production Facility is not a concern.

ii) The corresponding provision of the 1990 CAPL Operating Procedure did not refer specifically to disposal and injection wells. As the identified list of facilities in that definition was not exhaustive, those wells could fall within the definition if the other conditions were satisfied. This outcome may not have been appreciated fully under the 1990 document. An injection well must be approved by all of the Parties to fall within the scope of the definition, though, because of the significant potential impact on the exploitation of the reservoir.

iii) There will be circumstances in which the Parties have constructed water sourcing, handling and recycling infrastructure for the Joint Account to support a large-scale resource development. If the expected use is only for the ongoing development of the Joint Lands, the Parties may sometimes find it attractive to manage that infrastructure under this Agreement on at least an interim basis, rather than under a separate CO&O Agreement. This would require the Parties to negotiate an amendment at the time to apply the Production Facility provisions to that development infrastructure on a *mutatis mutandis* basis, so that the infrastructure would be governed by an agreement. The vision for the management of that infrastructure would probably change in due course if the Parties were considering an expansion or use for purposes other than the Joint Lands, though.

iv) The 1990 definition excluded refineries, cryogenic gas plants, acid gas or sulphur recovery facilities and sulphur forming, loading and remelting facilities. Paragraph (d) of the 2007 document was modified to exclude gas plants entirely. The Paragraph recognizes that the complexities of those facilities are such that they should be covered under a CO&O agreement, and the completion of the 1996 and 1999 versions of the PJVA documents makes this much easier than was the case when the 1990 document was prepared. It also reflects the practical consideration that those facilities would typically be used for Outside Substances at some point. Excluding this Paragraph would extend the scope of the definition beyond the minor class of facilities for which the document provisions were designed.

v) A Production Facility is not necessarily held by the Parties in the percentages of their Working Interests in the Joint Lands. A Production Facility may be constructed as an Independent Operation under Clause 10.13 or expanded as an Independent Operation under Clause 10.14.

vi) A facility initially constructed and operated as a Production Facility might cease to be one. If the Parties later enter into a CO&O agreement for a facility, it will no longer be a Production Facility under the Operating Procedure. Even if the Parties intend to enter into a separate CO&O agreement, the Operating Procedure at least ensures the Parties that the facility will be covered by a document until the CO&O agreement is finalized. The facility may also cease to be a Production Facility if it is subsequently used for Outside Substances. (See Clause 14.02.)

vii) Optional Paragraph (f) was introduced in the 2007 document, and supplements the protections provided by Clause 14.02. It recognizes that Parties working in a high-cost area may also wish to have a financial control on the facilities to which the document could apply. Parties that select this Paragraph would tailor the threshold to their particular situation. The threshold is based on the reasonable estimated cost, rather than the final cost. Basing it on the final cost could compromise the proponent if actual costs were higher than the threshold.

Regulations: The reference to the Parties has been included to ensure that both applicable provincial and federal rules apply. Because of the division of powers between the two levels of government, the federal regime focuses on bodies, rather than properties.

Reworking: This is a non-routine stimulation of a well that is not a Completion or Recompletion, although the costs are treated as Completion Costs for the purposes of the Clause 10.07 cost recovery process. Normal operations and maintenance work is not a Reworking, and would be handled as Operating Costs if a cost recovery applied to the well.

Sidetracking: i) Sidetracking is used in two contexts by technical personnel. One context is directional drilling conducted to bypass an obstruction in the hole or otherwise to overcome problems such as collapsed casing. The second is additional drilling conducted to relocate the bottom hole location of a well to a more prospective location, and the latter may also involve a plugging back of the original wellbore to a kick off point. For the purposes of the post-1990 documents, the term excludes a deviation to straighten the hole, to drill around an obstruction or to overcome mechanical difficulties. By implication, any such activity is *prima facie* within the scope of the approved Operation. (See also Subclause 3.01D.)

ii) For context, a "whipstock" is an inclined wedge placed in a wellbore to force a drill bit to start drilling in a different direction.

Spacing Unit: i) Note the introduction of the stratigraphic component to Paragraph (a). The Spacing Unit for a well being drilled to the Cardium includes jointly held rights in the applicable area to the base of the Cardium, but does not include the deeper rights. This modification should be read in conjunction with Paragraph (b) of the definition of Development Well and the associated annotations.

ii) Note the reference to the producing zone at the end of Paragraph (b), which was added for greater clarity in the 1990 document. There had been a general assumption that the normal Alberta spacing unit for a gas well is 640 acres in all zones in which the Parties jointly hold the section. As the Parties are free to drill and produce a Viking gas well on the same section as a Nisku gas well, it is clear that a production spacing unit has both an areal and stratigraphic component. Given the reference in the traditional definition to the three dimensional "area allocated to the well under the Regulations for the purpose of producing Petroleum Substances," the definition was certainly accurate as it stood in the 1981 CAPL Operating Procedure. However, the subtlety of the definition may not have been appreciated by some users.

The corresponding definition in the CAPL Farmout & Royalty Procedure provides a different result that reflects the traditional assumption about the stratigraphic component of a spacing unit for an earning well. The earned spacing unit thereunder for a gas well would be all earned formations in the section to reflect the earning outcome. However, other provisions of the document address the situation in which a second well is proposed on a "spacing unit" with an earning well prior to the application of the Operating Procedure to that "spacing unit" (i.e., before "Payout"). (See Clause 6.06 of the CAPL Farmout & Royalty Procedure and the associated annotations.)

iii) A Spacing Unit is not a static concept. A subsequent reduced spacing order will also change the Spacing Unit under the Operating Procedure. Users also need to recall that a reduced spacing order is not the same as a permitted increase in drilling density.

iv) No particular provisos or modifications to the definition of "Spacing Unit" were included for Horizontal Wells. The definition works in its current form for key provisions such as Articles 10.00 and 12.00 for Independent Operations and Abandonment. It is also expected that the Regulations will use varying definitions across jurisdictions, such that a simple "one size fits all" definition would create confusion if it conflicted with the applicable regulatory regime in place at the relevant time. If a specific definition is required, the Parties should agree on the Spacing Unit for any particular Operation for which the general definition is inadequate or amend the Agreement to address their circumstances.

v) Holdings and other increased drilling densities have limited direct impact on a well to which a cost recovery applies under Article 9.00 or 10.00, as the cost recovery applies only to the Non-Participating Party's share of production from the applicable well. A Participating Party must be aware, though, that they could see a reduction in the reserves to be drained by the well subject to the cost recovery.

vi) The Spacing Unit concept is an evolving one in areas of the north. Parties using the document for an area for which there is no Spacing Unit as such may need to clarify their expectations on a custom basis in their own agreement.

Title Administrator: This definition and the associated changes to Clause 3.10 in the 2007 document reflect the fact that the Operator's obligations may not extend to the maintenance of all Title Documents. Parties should consider this issue more carefully and address their expectations clearly. A Non-Operator with the land administration responsibility has corresponding rights and duties. (See also the annotations on Clause 3.10.)

This issue is complicated if a third party is the administrator of the Title Documents (e.g., farmor with a non-convertible ORR). The Parties should address their expectations on this issue clearly in their Head Agreement where appropriate. If, for example, a farmor with a Working Interest will retain the responsibility, it may be mutually beneficial for the farmor and the Working Interest owners to be clear that the applicable farmor has the same obligations and rights as the Title Administrator under the Operating Procedure on a *mutatis mutandis* basis. (*Mutatis mutandis* is a legal term that means "with the necessary changes in points of detail, meaning that matters or things are generally the same, but to be altered when necessary, as to names, offices and the like" (Black's Law Dictionary). In other words, the provisions of the Operating Procedure would apply on the same basis, other than for the difference in Party in this instance.) Similar considerations will often apply to a pooling agreement.

The issue is more complex for those situations in which there is no ongoing relationship between the Working Interest owners and the entity administering the Title Documents (e.g., purchase of deep rights from a third party). The Parties could require a special provision in a sale document or a side agreement of some sort, probably requiring the Operator to manage the interface between the Working Interest owners and that third party.

Title Documents: i) The acquisition of a freehold lease in "replacement" for an expiring lease does not fall within this definition unless the acquisition is through an AMI or the Parties otherwise agree to make the acquisition for the Joint Account. If, for example, the Operator were concerned about the validity of the current lease and it acquired another freehold lease for the Joint Account after discussions with the other Parties, it would be a Title Document. If the terms of a freehold lease did not provide the lessee with the unilateral option to obtain a successor lease, the lessee only had a non-exclusive right to obtain a new lease. This would not satisfy the test that the replacement document be "issued or derived therefrom".

Whether an Operator chooses to act unilaterally for such an acquisition is a different consideration. There will be many instances in which the Non-Operators will have an expectation that they be offered the opportunity to participate in any such acquisition. Whether any such acquisition of a new freehold lease will be a Title Document or not will be a question of fact and law. It would be difficult to make the argument, for example, if a Party reacquired a freehold lease 18 months after a primary term lease was allowed to expire.

ii) A typical "replacement" would be a lease selected from a B.C. drilling licence or a significant discovery licence issued from a Federal exploration licence. The "replacement" aspect was considered in the context of a new lease "executed in lieu thereof" in Canadian Natural Resources Ltd. v. Jensen Resources Ltd., [2014] 4 W.W.R. 213 (Alta. C.A.), reversing in part on a limitations issue [2013] 6. W.W.R. 836 (Alta. Q.B.). The Court found that the acquisition of an oil sands lease as a matter of right because of the status as the holder of a P&NG lease satisfied the "in lieu thereof" test.

Vertical Stratigraphic Wellbore: Subclause 8.01A requires the Party serving the AFE or Operation Notice for a Vertical Stratigraphic Wellbore to provide information about its vision to drill one or more Horizontal Legs therefrom, so that the recipients understand the contemplated Operation.

Well Pad: This definition is not limited to wells drilled for the Joint Account or wells drilled under this Agreement. Any custom negotiated provision addressing the use of a Well Pad for the development of the Joint Lands will focus on those wells. The broader language is used because of the possibility that the Well Pad could be used on a shared basis with other interest owners and be governed, to at least some extent, under a separate pad sharing agreement. (See Subclause 10.04A and the related annotations.)

Working Interest: i) The beneficial interest reference recognizes that the Working Interests are not necessarily the same as the registered interests in the Title Document. The Working Interests are identified in the Agreement, and can be modified by operation of the Agreement. This could be by operation of the Operating Procedure (such as forfeiture, surrender and disposition) or by operation of other provisions of the Agreement (such as conversion rights at payout or the abandonment provisions of the CAPL Farmout & Royalty Procedure). The linkage of the beneficial interest to the Working Interest held under the Agreement precludes a Party from circumventing the disposition requirements with a “silent partner”.

ii) A Party subject to a cost recovery under Article 9.00 or 10.00 retains its Working Interest in the applicable Joint Lands (versus its share of production volumes from the well).

Paragraph 1.02A(d): This Paragraph ensures that terms such as "Abandon" and "Abandoning" can be used in the same context as “Abandonment”.

Paragraph 1.02A(f): References such as “including” outline a list of examples that is not necessarily exhaustive. The context is actually “including, without limitation,”.

Paragraph 1.02A(i): This is included for the benefit of Parties which are both a Working Interest owner under the Operating Procedure and the lessor under a Title Document. A Party’s capacity as lessor is not impacted directly by the application of the Operating Procedure.

Paragraph 1.02A(j): This Paragraph has been included for clarity in handling sales taxes that are refundable (such as GST) when calculating amounts payable or to be recovered under the Operating Procedure. It is aligned with the joint election on GST under the Accounting Procedure.

Paragraph 1.02A(k): i) This clarifies the timing problems inherent in the use of such terms as “within” or “at least” when referring to a specific number of days, and is similar to the general timing provision in the Alberta Rules of Court. A similar provision was introduced in Paragraph 103(c) of the 1990 document.

ii) The clock basically starts on the day after a typical notice is received.

iii) The period within which an act must be performed, such as Commencement of an Operation or response to a notice, is generally extended to the next Business Day if the last date for performance is on a weekend or a statutory holiday. There is an exception for the 24-hour Casing Point election under Article 9.00. Payment is due on the preceding Business Day under Clause 103 of the PASC Accounting Procedure if the due date for a Joint Account billing is on a weekend or a statutory holiday.

To provide otherwise for a response to a notice, for example, would enable the Party that controls the initiation of the notice process (e.g., ROFR notice or Operation Notice) to serve its notice so that the Parties have less than the prescribed period for response. An issuing Party that does not want to see the response period extended over a weekend can easily avoid the result by serving its notice a day or two earlier.

iv) The initial portion of this Paragraph does not apply to 24 and 48-hour notices under Subclause 9.02B and Paragraph 10.02B(b). Because costs are being incurred on a real time basis, those notices require a response within a specified number of hours, not days or Business Days. However, the last sentence applies to defer a response to the next Business Day for a 48-hour notice if the response period expires on a day that is not a Business Day. To provide otherwise might encourage surprise notices on a Friday afternoon. An Operator can mitigate the negative impact of this provision by alerting the other Parties to its plans in advance. Operators also need to understand the impact of Article 22.00 on the receipt of a notice.

Paragraph 1.02A(l): The provisions of Clause 1.02 apply on a *mutatis mutandis* basis to all of the components of the Agreement. This provides a better context for the Head Agreement and the other Schedules, as those other components will typically not include a comparable provision.

Subclause 1.02B: This Subclause is designed to override a legal rule of construction (“*contra proferentem*”) whereby an ambiguity in an agreement is held against the Party that drafted the agreement. (See, for example, Mobil Oil Canada Ltd. v. Beta Well Service Ltd. (1974), 43 D.L.R. (3rd) 745 (Alta. S.C., App. Div.) and Morrison Petroleums Ltd. v. Phoenix Canada Oil Co., [1997] A.J. No. 275 (Alta. Q.B.). The latter is interesting because the provisions in question were in the standard form 1981 CAPL Operating Procedure.)

Clause 1.03: i) It was much more likely that this Clause would have potential application during the period in which users manually completed elections on a hard copy of the CAPL Operating Procedure. The typical industry practice of including election sheets as a Schedule to Agreements has largely mitigated the possibility that this Clause could apply.

ii) Article 21.00 has been presented as an exception to the normal default outcome because the more typical election at the time the document was written was not to select the application of that Article.

Subclause 1.04A: i) The Working Interests, the well classifications and the allocation of legal responsibility in the document (i.e., Article 4.00) apply among the Parties, notwithstanding the registered interests in the Title Documents and the well classifications and responsibility for Operations prescribed by the Regulations. If the registered interests in the Title Documents do not correspond to the Working Interests (as is often the case), the traditional conflicts provision literally states that the registered interests become the Working Interests due to the conflict with the Title Documents.

The liability reference is included because of the degree to which the Title Documents and the Regulations may require the lessee or well licencee to assume legal responsibility for losses. While this may be in the public interest, it is clear that the provisions of the document allocating legal responsibility among the Parties should continue to govern their relationship to share responsibility for Losses and Liabilities.

ii) The Operating Procedure will generally override the provisions of another Schedule if there is a conflict. However, there is an exception if a Schedule expressly overrides the Operating Procedure, such as Clause 17.01 of the 1997 CAPL Farmout & Royalty Procedure, Clause 18.01 of the 2015 CAPL Farmout & Royalty Procedure and Clause 2.02 of the 1993 CAPL Assignment Procedure.

Subclause 1.04B: Insofar as a provision is severed from the Agreement, the consideration under the Agreement has been altered to some extent. The proviso in the second last sentence was introduced in the 2007 document. It requires the Parties to make a good faith effort to include a replacement term that gives effect to the original intention in a legally binding manner.

Subclause 1.05A: i) There have been a number of major cases in this area since the late 1980s, and some pertain to the oil and gas and mining industries. They are addressed in Part II of the Addendum at the end of these annotations. This issue will also frequently be raised in conjunction with a claim for breach of confidence when a misuse of confidential information is alleged. The law in this area is evolving. What is clear is that a Party that exercises discretion in a manner that it knows will harm its co-venturers may be vulnerable to legal challenge if its behaviours appear dubious.

ii) Notwithstanding this Subclause, the first sentence arguably applies to the relationship of the Parties with third parties, not the relationship of the Parties to each other. Consider this provision in the context of Clause 5.06 for reimbursement of the Operator. If a Party defaulted in its obligation to pay its share of costs incurred for the Joint Account, Clause 5.06 ensures that the burden is shared by the non-defaulting Parties until (and insofar as) the Operator can use its remedies to recover the unpaid amount. Otherwise, the Operator would always have to bear that burden alone.

iii) The statement of intention cannot exclude the Court's jurisdiction to determine that there is a fiduciary relationship for a particular duty.

iv) The provision may not be effective against third party litigants. A Court is not obligated by the provisions of the contract. Unless it apportions legal responsibility among defendants, a successful plaintiff can enforce its judgment jointly against those defendants held responsible for the loss.

v) One of the major reasons for the inclusion of this type of provision is to attempt to ensure that the business relationship is not legally characterized as a partnership, largely because of the potential adverse tax consequences of that classification. Although other Working Interest owners in a property are commonly referred to as "partners" in the oil and gas industry, this just reflects a traditional choice of terminology, not a description of the legal relationship. A more accurate legal description would be to describe other owners as "co-venturers".

vi) Although the Operator may contract for the leasing or acquisition of Joint Property in its own name, the rights acquired by the Operator for the Joint Account become Joint Property. The Non-Operators own their respective Working Interest shares of acquired Joint Property as tenants in common. (This would include surface rights, as noted in the annotations on Clause 3.09.) See Direct Energy Marketing Ltd. v. Kalta Energy Corp., [2003] A.J. No. 1624 (Alta. Q.B.) in the context of the 1974 CAPL Operating Procedure.

Subclause 1.05B: The Parties are also competitors. A Party may generally make decisions based on its perception of its own interests, subject to Subclause 1.05A and the other obligations in the Agreement, including any express obligations not to exercise discretion unreasonably.

Subclause 1.05C: The Operator does not have any special obligation to apply knowledge from other project areas to the Joint Lands.

Clause 1.06: i) The assumption is that the Parties want the Courts of Alberta to have jurisdiction, even if the Joint Lands are located outside of Alberta. There are two reasons for this. Firstly, the logistics of managing legal proceedings would generally be easier, since the Parties' head offices are typically located in Calgary. Secondly, the Courts of Alberta have an extensive body of oil and gas case law that provides a valuable context for any litigation involving the Operating Procedure.

The Parties could easily modify this provision or include a provision in the Head Agreement to apply the laws of another jurisdiction if the reference to Alberta does not meet their needs (e.g., Parties based in Saskatchewan conducting Operations there). Corresponding modifications would be required for Clauses 1.07 and 21.03 (or the introduction to Article 21.00 if it is not selected to apply) and probably the definition of Business Day and the time zone reference in Paragraph 1.02A(h).

ii) Notwithstanding that the Operating Procedure may stipulate that the Courts of Alberta have jurisdiction, this is not necessarily determinative at law. (See, for example, Encal Energy Ltd. v. Numac Energy, [1986] B.C.J. No. 1918 (B.C.S.C.).)

Clause 1.07: i) On March 1, 2001, a new *Limitations Act* (Alberta) came fully into force in Alberta. Under that Act, all actions must be commenced "within two years of when the claimant knew or ought to have known of its claim". Many oil and gas industry practices typically require a longer time to address and resolve claims before an action may suitably be commenced. For example, the widely accepted audit process in the industry permits audits to be conducted up to 24 months after the end of the calendar year in which Operations occur. The coming into force of the *Limitations Act* created a conflict between these industry practices and limitations rules in Alberta, and created the possibility that the limitation period for bringing a claim may expire before an audit even occurs.

In recognition of this problem, the oil and gas industry used the right given under the *Limitations Act* to extend the limitation period for disputes arising under agreements between industry members. Under the guidance of the Petroleum Accountants Society of Canada, an industry task force developed language that would extend the limitation period under oil and gas industry agreements. This language was adopted by over 1200 companies in the Industry Agreement regarding Limitations dated January 1, 2001, and it generally applies to oil and gas industry agreements. It has become the standard method of treating limitation periods under industry agreements.

This Clause is substantially consistent with the language recommended by that task force. Generally, the provision extends the limitation period from two years to four years. Paragraph (a) applies to industry agreements that contain an audit provision requiring audits to be completed by a specified time, and it addresses the question of when a Party is treated as having "ought to have known" of a claim by providing that the limitations "clock" begins to run at the end of the period by which an audit was allowed by the agreement to have been performed.

Additional information about the *Limitations Act* (Alberta), its impact on oil and gas industry agreements and the Industry Agreement regarding Limitations can be found at *www.petroleumaccountants.com*.

ii) The Clause was introduced in the 2007 document because of the assumption that the vast majority of Parties would prefer to see the issue addressed in this manner, rather than having to include a custom provision in their Head Agreement. The alternative would potentially see Parties forgetting to include the provision or including inconsistent and sometimes poorly drafted provisions. Parties that believe that the Clause substantively alters their rights in a way that is unacceptable to them remain free to modify or override this Clause.

Clause 1.09: An amendment generally is not effective unless it is executed by the Parties. Examples of exceptions to the general rule include a notice of a changed address for service under Clause 22.02, a modification to rates under Clause 2.03 or 2.05, the approvals provision of the PASC Accounting Procedure and the notice of assignment process under the CAPL Assignment Procedure. The more generic reference has been included because any modifications negotiated to the Operating Procedure or the Accounting Procedure could create additional exceptions.

Although the corresponding provision in the pre-2007 documents referred to amendments to the Operating Procedure, the reference in this Clause is to the Agreement. By definition, this constitutes the entire Agreement, rather than just the Operating Procedure. It also applies to the Head Agreement in the absence of any express conflict with the Head Agreement.

Clause 1.10: i) The Clause covers actual and anticipated breaches. A prudent Party would seek a waiver before a breach, not after the fact.

ii) A Party that does not exercise a right within a prescribed time period cannot rely on this Clause to preserve its rights for that particular matter.

iii) The waiver concept was reviewed in Tri-Star Resources Ltd. v. J.C. International Petroleum Ltd., [1987] 2 W.W. R. 141 (Alta. Q.B..) and Kaiser Francis Oil Co. of Canada v. Bearspaw Petroleum Ltd. (1999), 240 A.R. 59 (Alta. Q.B.). The Tri-Star case pertained to a CAPL Operating Procedure that included an earlier version of this Clause. One of the issues was an alleged verbal statement by an officer of a non-operator that it would not attempt to remove the operator if its funds were protected from the operator's creditors. The Court found that a waiver must be in writing because of the mandatory nature of the provision. The Kaiser Francis case pertained to a pre-CAPL Operating Procedure that did not include a waiver clause. One of the arguments was that the non-operators were estopped from removing the party acting as successor operator because their conduct in working with that party as operator represented their consent to its appointment. The Court found, on the facts, that there had been "indulgences" that did not constitute a waiver of the non-operators' rights with respect to the appointment of the new operator.

Clause 1.11: i) The Operating Procedure will supersede the Head Agreement and any Schedule (e.g., CAPL Farmout & Royalty Procedure) insofar as they become ineffective by their own terms after the Operating Procedure begins to apply. On the other hand, the Head Agreement or the CAPL Farmout & Royalty Procedure may include terms that are stated to survive once the Operating Procedure becomes effective. An existing area of mutual interest created under the Head Agreement and, if applicable, the CAPL Farmout & Royalty Procedure would continue by its own terms.

ii) Many blocks have overlapping agreements that are binding on only some of the Parties (e.g., an owner farmed out a portion of its interest to a third party). In this type of situation, a notice of assignment (NOA) should be processed as soon as is feasible, so that 100% of the Working Interests are managed under the same Agreement. The last sentence is included because of the possibility that there may be unique obligations that apply between some Parties because of another agreement between them that does not affect the other Parties.

iii) Care must be taken when preparing a non-cross-conveyed pooling agreement. To what degree will the initial agreement for a tract remain active for the Parties holding those rights? This issue is particularly relevant if that agreement included a ROFR. The inclusion of item (ii) in the Clause as of the 2015 document was to address primarily the possibility that the Joint Lands might again be subject to the original agreement following termination of a pooling agreement. (See also annotation (v) in the Miscellaneous Annotations on ROFRs in Part III of the Addendum to the annotations.)

iv) Item (iii) was added as of the 2015 document to be clearer that this Clause did not itself alter any existing obligation of a Party with respect to an ORR accruing to another Working Interest owner. However, Article 15.00 would continue to govern the responsibility for that ORR if the encumbered Party surrendered its Working Interest or became subject to a consequence of non-participation.

Clause 1.12: This provision is structured broadly enough to be used for both jurisdictions with perpetuities legislation, such as Alberta, and other jurisdictions in which the conventional common law principles apply. Although the Alberta Act does include a "life in being" approach, Section 18 of the Act currently includes a fixed 80-year period for commercial transactions, and Subsection 18(2) specifically addresses rights of first refusal.

Clause 1.13: This provision was modified significantly from the traditional provision in the 2007 document. The overall result remains the same, though, in that the relevant Parties are choosing to file such elections as are permitted to avoid a partnership for purposes of U.S. taxes. Insofar as the Joint Lands are located in the U.S., the Parties should review this Clause at the time in the context of their circumstances. A Party that believes the Clause does not meet its particular requirements remains free to replace it with a customized Clause.

Clause 1.14: i) Confidentiality obligations continue under Clause 18.05. The provisions relating to audit, liability, indemnity, disposal and salvage of material and enforcement on default also continue for such period as the rights and obligations apply under the Regulations. This is particularly relevant for liabilities that were only contingent at the date of termination, given the increased sensitivity to environmental issues.

ii) Many users terminate the agreement file and remove it from their land system once the Joint Lands expire. This practice, however, is inconsistent with the Term Clauses of all versions of the CAPL Operating Procedure. Each version of the document is clear that the Operating Procedure continues to remain in effect through at least the Abandonment of any outstanding wells, the receipt of the applicable reclamation certificates and any associated final settlement of accounts among the Parties. There cannot be any final settlement of accounts until at least completion of the reclamation process and payment of the associated costs and expenses. One might also attempt to argue that there cannot actually be any final settlement of accounts in any event until expiry of the audit period pertaining to the most recent financial transactions under that agreement.

The Operator's issuance of JV invoices for associated surface rentals or reclamation costs often results in delays in payment and billing disputes, since recipients do not readily understand the legitimacy of the charges. This is a complex area, for which many of the potential solutions would be worse than the problem. The issue can be mitigated significantly through: (a) records retention processes in which files remain in the land system with an active status for the period between expiry of P&NG rights and completion of the reclamation process; and (b) greater awareness about the implications of the issue when preparing a notice of assignment for any agreement for which there are surface rights in the reclamation process.

iii) The post-1990 documents are much clearer about Environmental Liabilities associated with Joint Operations that only become apparent after the final settlement of accounts. Subject to any special allocation of responsibility under Article 4.00, the remedial costs will be for the Joint Account. That being said, there will be some enforcement issues in practice if a previous Party no longer exists at the time the expenditure is required.

iv) The parenthetical "or other Party" reference in Paragraph (b) recognizes that the Operator may not exist when the problem arises.

Clause 1.15: This Clause is designed to protect against changes to the standard form that were not identified when the document was prepared. It is necessary because of the likelihood that Parties will prepare their document electronically, rather than by attaching a CAPL watermark copy. It is conceptually consistent with the comparable provision in the 1997 CAPL Farmout & Royalty Procedure, the 1997 CAPL Overriding Royalty Procedure, the 2000 CAPL Property Transfer Procedure, the 2007 document and the PetroDocs version of the 1990 CAPL Operating Procedure.

In essence, it ensures that modifications that have not been identified in the Operating Procedure, the Agreement or a Schedule of elections and modifications are not effective. The CAPL standard form will apply to the provisions as if the modifications have not been made.

Subclause 2.02A: One of the foundation principles of the 1990 document and subsequent updates is that an Operator is appointed to serve for the benefit of the Joint Account. This is very different than the view that the role is somehow the property of the Party acting as Operator. The Operator's ability to fulfil its duties and obligations is largely a function of its ongoing financial viability. It is subject to immediate replacement, by notice, if any of the conditions in Paragraphs 2.02A(a)-(g) apply to it. An interim Operator is appointed on the same basis as under Subclause 2.06D, pending selection of a successor Operator by the Parties under Clause 2.06.

Paragraph 2.02A(a): i) Notwithstanding the clear wording of provisions such as this Paragraph, there can be a major difficulty in attempting to enforce such a provision. As shown by Norcen Energy Resources Limited and Prairie Oil Royalties Company, Ltd. v. Oakwood Petroleums Ltd. (1988), 92 A.R. 81 (Alta. Q.B.), Courts may be willing to protect an insolvent Operator from the imposition of such a provision.

The case pertained to an interpretation of Section 11 of the *Companies' Creditors Arrangement Act* (Canada). This act is similar in intent to the concept of "Chapter 11" protection in American law, and Section 11 provides a Court with a broad discretion to "make any order that it considers appropriate in the circumstances". This discretion reflects a public policy objective to preserve the value of an insolvent company by allowing it time to continue to operate as a going concern in the hope that it will be able to overcome its financial difficulties or make an arrangement with its creditors.

Norcen was not a creditor of Oakwood, but the Court used Section 11 to affect the contractual relations between the insolvent Party and a non-creditor. It granted a two-month stay that prevented Norcen from becoming Operator under Clause 202 of the 1981 document, even though the Court recognized that Oakwood had been insolvent for some time. The case was determined less than two weeks before expiry of the stay, and was not appealed. This protection from the application of Clause 2.02, however, would not apply if the Operator makes a proposal to creditors under the *Bankruptcy and Insolvency Act* (Canada). (See Tri-Star Resources Ltd. v. J.C. International Petroleum Ltd., [1987] 2 W.W.R.141 (Alta. Q.B.).)

The post-1981 documents differ from the 1981 document. The differences include: (a) a reference to the *Companies' Creditors Arrangement Act*; (b) a potential removal by vote under Paragraph 2.02B(a); and (c) a waiver of relief Clause (25.05), through which a Party waives certain rights it may have at law or under the Regulations. The 2007 document introduced a prohibition that an Operator may not seek relief from the application of this Subclause. Paragraph 2.02A(b) and Subclause 2.06F are also relevant to the insolvency issue, and were introduced in the 2007 document. Orders issued under the *Companies' Creditors Arrangement Act* to date have not differentiated between versions of the document, and Non-Operators have not litigated the issue. It is unclear if a Court would allow Non-Operators to remove an insolvent Operator. It is also not clear if a Court would use its discretion to preclude replacement of an insolvent Operator under Paragraph 2.02B(a).

Because of the possibility that a Court may not allow removal of an insolvent Operator, Clause 5.07 was modified in the 2007 document. It terminates the Operator's right to commingle funds held hereunder with the Operator's funds if any of the conditions in Paragraph 2.02A(a)-(d) apply and the Non-Operators are prevented from replacing the Operator.

ii) The Court also determined in the Norcen case that insolvency was to be given its normal meaning in interpreting the 1981 provision. Oakwood had attempted to argue that it was commercially solvent for day-to-day matters and that the Operating Procedure contemplated only commercial insolvency. The corresponding Paragraph (a) of the 1990 document was amended to reflect the Court's interpretation of the intention of the 1981 provision. In practice, it could be very difficult to determine if or when insolvency had occurred. A Party would require detailed information about the Operator's business affairs if the insolvency issue were to be considered in the absence of an Operator's application for debtor relief protection. It would be unlikely to receive any significant cooperation from the Operator prior to commencing an action.

iii) Following appointment of a receiver, a lender will generally provide the funds required to ensure that debts are then paid as they become due. The onus on the Non-Operators to prove insolvency could then be more difficult.

iv) There may be circumstances in which the other Parties would waive the immediate removal of the Operator.

v) The notice must be a *bona fide* notice. It must specify the basis for replacement and include verifiable evidence substantiating in reasonable detail the basis for removal.

Paragraph 2.02A(f): This Paragraph was introduced in the 2007 document, and reflects the increased vigilance of regulatory authorities, such as the Alberta AER, in assessing the financial capability of an Operator to fulfil Abandonment and reclamation responsibilities. An Operator that does not meet the regulatory criteria will typically be permitted to operate assets by submitting a deposit for its own account. A qualification has been included for situations in which the Operator is a registered partnership or trust, as all such licences and approvals would be held by the managing partner, another partner in the partnership or an Affiliate in the case of a trust.

Paragraph 2.02A(g): i) An Operator that is in the process of assigning its Working Interest is not subject to immediate replacement because it has initiated the process of formally assigning the interest. The Operator will continue to be responsible for operating the property during the transitional period to the applicable "binding date", at which point a successor Operator appointed under Clause 2.06 will assume the Operator's rights and duties. That successor may be an interim Operator selected under Subclause 2.06D if the Parties have not been able to appoint an Operator under Subclause 2.06C. Notwithstanding the timing specified by Subclause 2.06E and the notice of assignment process under Subclause 24.04A, the Parties should consider a mutually agreed acceleration of recognition of the Operator's assignee if it will be the successor Operator.

ii) A Vendor will often prepare assignment documents on the assumption that its assignee will succeed it as Operator. This may sometimes be clear because of the distribution of Working Interests. However, Closing will often occur prior to appointing the successor Operator under Subclause 2.06C. The better practice is to try to appoint the successor Operator prior to Closing where feasible and warranted. If this is not feasible, it may be beneficial to defer registering the applicable surface and licence transfers until the new Operator is confirmed. In practice, the approaches on this issue vary widely, and are influenced by such factors as the distribution of Working Interests, the logistics associated with a large transaction, the regional positions of the Parties (including infrastructure), the value of the property and the anticipated sensitivities of the other Parties on this issue.

iii) An Operator may sometimes have an Affiliate or another entity act as a contract operator on its behalf.

Paragraph 2.02B(a): i) This Paragraph is much stronger than the traditional Clause 2.03 challenge mechanism. It was introduced in the 1990 document with a greater than 50% WI threshold that was increased to at least 60% in the 2007 document. It enables the Non-Operators to remove an Operator against its will. It reflects the evolving philosophy that the Operator is ultimately the Parties' representative, to serve only as long as it maintains a critical mass of Working Interest support. Given: (a) the significant costs potentially associated with the removal of an Operator during the development/production phase; (b) the potential for the disruption to Operations; and (c) the business considerations associated with such a removal, the most practical impact of this provision is to reinforce the Operator's accountability to the owners for its performance. Although quite different from the traditional challenge mechanism (Clause 2.03), the use of a voting procedure/no cause challenge mechanism is used in conventional unit agreements and some international joint operating agreements. One might argue that this provision should provide the Operator with the right to attempt to rectify its perceived defaults or shortcomings, as this would probably happen in practice. The problem with including such a provision would be the difficulty in trying to quantify if the Operator is not meeting the performance standard for qualitative problems.

The major advantages to this Paragraph are: (a) not having to establish grounds for removal; (b) not having to wait for very serious problems; (c) avoiding evidentiary issues; (d) having legal resolution on an accelerated basis if the Operator is unwilling to comply; and (e) possibly avoiding the result in the Norcen case noted above if the Operator is seeking debtor relief protection.

ii) The removal of an Operator is a very serious step that should be regarded as an exceptional right. There are potentially significant direct costs because of the loss of continuity in the management of the property during at least the transitional period. There is likely to be a very real ongoing cost because of the damage to the Parties' relationship. Parties exercising this right in a capricious manner must also recognize the potential impact of this decision on their reputation in the marketplace and the potential that this could adversely impact their access to new opportunities.

iii) A Non-Operator holding at least a 60% Working Interest has the right to become Operator by notice to the other Parties, assuming it is not otherwise disqualified. This reflects the fact that it is paying at least 60% of the cost of Joint Operations (>66% in the 1990 document).

iv) Although not mentioned specifically in the case, this Paragraph appears to have been the subject of Signalta Resources Ltd. v. Land Petroleum International Inc., [2007] A.J. No. 496 (Alta. Q.B.) in the context of the 1990 document. In that case, Signalta obtained the consent of all Non-Operators to replace the Operator after Signalta acquired the interest of another Non-Operator. The Operator attempted to retain operatorship, based primarily on an argument that Signalta's predecessor was indebted to it under the agreement. This was even though the Operator did not object to the proposed assignment of the Working Interest to Signalta in accordance with the 1993 CAPL Assignment Procedure. The Court granted injunctive relief to require the Operator to transfer operatorship to Signalta.

Paragraph 2.02B(b): The use of the default mechanism may be a very helpful tool to address deficiencies in an Operator's performance. Any such default notice must be in sufficient detail to enable the Operator to appreciate the nature of the alleged default. This is particularly important because of the real possibility that there could be litigation about the validity of the notice or the adequacy of the Operator's response.

Paragraph 2.02B(c): The Operator is required both to commence rectifying the default and to continue diligently to remedy the default. The notice also requires the Parties to identify the basis for their opinion that the Operator has not rectified the default diligently.

Clause 2.03: i) Limiting a challenge to an offer to conduct Joint Operations on "more favourable" terms and conditions than the Operator creates a serious, if not insurmountable, obstacle for the challenger. This is because of the obligation to assume sole responsibility if the more favourable terms are not delivered after a successful challenge. As it is difficult to quantify qualitative changes, it seems largely limited to financial terms. How, though, can a challenger give more than its best cost estimate when exploration costs reflect such factors as weather conditions, exploration success (testing costs), mechanical difficulties, the demand for equipment, changes in input costs and inflation? Similar challenges exist for a concern about Operating Costs. The problem might also be the Operator's technical performance or behaviours, rather than cost performance. In practice, the challenge might only be on the basis of overhead rates, where this would have the greatest financial impact on a mature, producing property.

The mechanism may be useful in some circumstances, in that it at least enables a Party to file a "complaint". However, the "no cause" replacement mechanism in Paragraph 2.02B(a) provides the Non-Operators with far greater protection in practice.

The 1990 version of this Clause was considered in Diaz Resources Ltd. v. Penn West Petroleum Ltd., 2010 CarswellAlta 2890 (Alta. Q.B.). The challenging Non-Operator had issued its challenge on the basis of eliminating joint account charges for a Production Office/Field Office and First Level Supervision in the field without any attempt to quantify the financial impact of these changes on the joint account or otherwise commenting on the manner in which its assumption of the position would impact the joint account. The Court found that the information provided in the challenge notice did not satisfy the requirements of the Clause. The Court determined that it did not need to address other concerns of the Operator about the ability of the Non-Operator to take over responsibility for managing the property. This case reinforces the challenge in trying to use this Clause.

ii) The challenge mechanism might also be a helpful tool to use if the Operator is unwilling to place Suspended wells back on production.

iii) A challenge could take about 3.5 months to effect if steps occur at the latest times in the Clause versus five months in the pre-2007 documents.

iv) The Non-Operators could consider assuming a more active role through the use of the Independent Operation process under Article 10.00 if the Non-Operators' concern is the Operator's reluctance to proceed with a work program.

v) The replacement of the Operator under this Clause does not protect the new Operator from the application of any of the removal mechanisms in Clause 2.02, including Paragraph 2.02B(a). The Parties must be able to remove an Operator that is not performing to their satisfaction. To provide otherwise would place an Operator appointed under this Clause in a better position than any other new Operator. (See also Clause 2.05.)

vi) The existing Operator that matches a challenge and a new Operator that effected a challenge basically have accountability for operating on the challenge terms for two years.

Clause 2.04: i) An Operator that has served notice under this Clause remains subject to the possibility of earlier replacement under Clause 2.02.

ii) The minimum notice period was reduced from 90 days to 45 days in the 2007 document. This reflects the fact that most resignations are in the context of sales. The change also facilitates A&D transactions by aligning the period more closely to the timing in the CAPL Assignment Procedure.

Clause 2.05: i) This Clause basically provides an Operator with an opportunity to obtain improved financial recoveries in circumstances in which the Non-Operators are not willing to amend the rates and elections in the Accounting Procedure. It can be particularly helpful to an Operator if the cost recovery under the Agreement is so low that the Operator is considering resignation.

Under this Clause, the Operator would issue notice of the terms and conditions under which it would be prepared to remain as Operator. Any Non-Operator that objects must, in essence, issue a "Challenge Notice" relative to the Operator's proposal. An Operator considering use of this Clause needs to realize that it is allowing itself to be replaced if a Non-Operator is willing to operate on better terms than the Operator's offer.

ii) An Operator may not use this mechanism again until it has operated under any previous Operator's Notice served by it for at least two years.

iii) As noted in the annotations on Clause 2.03, an Operator appointed under this Clause may be replaced under Clause 2.02.

Clause 2.06: i) Ignoring the challenge scenario, a new Operator will be appointed under Clause 2.06 if the Operator resigns or is to be replaced. Generally, no Party may be appointed as Operator unless it has given its written consent to the appointment. However, the Party with the largest Working Interest will serve as interim Operator under Subclause 2.06D if the Parties cannot appoint a successor Operator. Under no circumstances, though, will a provision of this Clause reappoint as the successor Operator a Party that: (a) would be subject to immediate replacement under Subclause 2.02A; (b) had been replaced as Operator under Clause 2.02 within the preceding 30 months; or (c) is then subject to a notice of default issued under Clause 5.05. For purposes of Subclauses C and D, an assignee that will be a Party at the time the replacement of the outgoing Operator is effective will be regarded as a Party for the purpose of being eligible to be Operator at that time.

ii) The pre-2007 versions of the document did not clearly address the situation in which the Operator resigns because of a disposition to an arm's length assignee. The Operator, its assignee and the other Parties are all motivated to determine the successor Operator under Subclause C before the Operator's resignation becomes effective under Subclause E. This is typically through a letter agreement respecting the change of Operator. (A Party that does not notify the other Parties of its vote/response within 15 Business Days after receipt of a notice requesting confirmation of the successor Operator is deemed to have approved that appointment.) The interim Operator process in Subclause D will apply if the Parties have not determined the successor Operator as of that time. Subject to the disqualification mechanisms prescribed by Subclause B, the Operator's assignee is eligible to replace it under Subclause C or, if applicable, D.

The document is not prescriptive about when the Operator must initiate the replacement process resulting from a disposition of its Working Interest. Clause 2.04 allows it to resign shortly after closing, so that its successor will be in place by the "binding date" of the resultant notice of assignment. An Operator might choose to be more proactive and initiate the process on closing occurring or even prior to closing, contingent on closing occurring.

iii) Note the special 60% single owner qualification in Subclause C. This has been included for consistency with the proviso in Paragraph 2.02B(a). The threshold was lowered from greater than 66% in the 1990 document to at least 60% in the 2007 document.

iv) The Operator has flexibility on the timing for initiating the process to confirm its successor under Subclause C. The former Operator may vote on its replacement. The former Operator has a vested interest in seeing its Working Interest share of the assets managed effectively if it is retaining a Working Interest. If it is disposing of its Working Interest, it will usually vote on behalf of its assignee if the decision is made prior to the "binding date" under the applicable notice of assignment. (The assignor would continue to retain the general rights and obligations for the assigned Working Interest until the binding date under the notice of assignment. The agreement between the assignor and the assignee would typically govern the assignor's obligation respecting that vote.) An assignee that is already a recognized Working Interest owner would have a voting status for its existing interest.

v) Subject to the general disqualification limitations in Subclause B, the Non-Operator in a two Party scenario will have the right to become the Operator. However, it must hold more than a 40% Working Interest if the appointment of a successor Operator is because of the Operator's disposition of its Working Interest in the applicable Joint Lands. Pre-2007 versions of the document were less than satisfactory if the triggering event was the Operator's disposition of its Working Interest. The 1974 document did not address the issue, the 1981 document did so without a minimum threshold and the 1990 document addressed it with a *de facto* Working Interest threshold of 34%, given the general right of a Party holding more than a 66% Working Interest to become the Operator by notice in the 1990 document. The selection of the >40% threshold and the reduction of the threshold in Paragraph 2.02B(a) and Subclause 2.06C of the 2007 document from >66% to at least 60% were designed to balance the respective needs of the Parties. An owner with 60-66% Working Interest has greater rights than provided under the 1990 document, while a Non-Operator holding a large Working Interest (i.e., more than 40%) retains the ability to offer operational continuity to the property.

vi) An interim Operator will always be appointed if the Operator is removed immediately under Clause 2.02. There will, however, be many circumstances in which the interim Operator and the successor Operator will be the same, with confirmation of this occurring in a parallel process to the interim appointment.

vii) An interim Operator will also need to be appointed under Subclause D if a successor Operator has not yet been appointed under this Article when the replacement of the outgoing Operator is effective under Subclause 2.06E. Inherent in any such appointment is that the former Operator and new Operator would need to proceed with all required transfers so that it could perform its duties. An assignee that will be a Party as of that time will be eligible to be the interim Operator if it is not otherwise disqualified under Clause 2.06.

It is possible that a Party would become interim Operator against its will, although the Parties would typically attempt to avoid this. It is important to remember that Subclause D is always subject to Subclause 2.06B. A Party could be disqualified from being selected as the interim Operator if, for example, it were insolvent or it could not satisfy the Paragraph 2.02A(f) requirement to be eligible to hold well licences.

viii) Subclause E prescribes the effective date of the change of Operator. The general rule is that it will be on the 1st day of the second calendar month after the determination. The CAPL Assignment Procedure would also apply to a disposition through which an Affiliate of the Operator succeeds it as Operator. There is different timing for the resignation and challenge type mechanisms in Clauses 2.03-2.05. The outgoing Operator retains its rights and obligations during the interim period until its replacement is effective. This ensures that there is no gap in accountability for performance of the Operator's duties. If it is disposing of its Working Interest to an assignee that will be replacing it as Operator, the Parties might want to accelerate the timing for recognition of the assignee, notwithstanding the timing specified in this Subclause or under the notice of assignment. This recognizes the mutual benefits of having a contractual relationship with the successor Operator in place at the earliest feasible date and the practical fact that the Operator is unlikely to be highly motivated to operate the property after closing its transaction.

ix) Subclause F ensures that an Operator being validly replaced would not have any claim against the other Parties as a result its removal. It does not limit the Operator's remedies if Parties are trying to replace it in contravention of the requirements in Article 2.00.

x) The difficulties potentially associated with the appointment of a new Operator are illustrated by Kaiser Francis Oil Co. of Canada v. Bearspaw Petroleum Ltd. (1999), 240 A.R. 59 (Alta. Q.B.). This case pertained to a pre-CAPL Operating Procedure in which the Operator purported to appoint its purchaser as Operator. Although the agreement did not include an unrestricted ability to make the transfer, the Court regarded operatorship as being part of the vendor's interests that fell within the scope of "miscellaneous interests" under the P&S Agreement. Change of Operator letters had been sent to the non-operators for their execution. Although they were not signed, the purchaser acted as operator for some time. One of the non-operators then tried to become Operator with the support of the other non-operators. On the facts, the Court found that the non-operators had not waived their rights with respect to the appointment of Operator. (See also the annotations on Clause 1.10.) The case shows the importance of having appropriate documentation finalized at the earliest opportunity for appointment of a new Operator.

Clause 2.07: i) This Clause and Clause 2.08 apply to all changes of Operator contemplated in Article 2.00 (involuntary, voluntary and assignment).

ii) An outgoing Operator is responsible for outstanding accrued obligations, and retains its rights for any amounts owing to it.

Clause 2.08: i) The Clause specifies that an audit will be conducted within a certain time. It will often be appropriate to waive this requirement, particularly when dealing with undeveloped lands or minor value properties that are not complex. The provisions of the Accounting Procedure otherwise apply to the audit, including the resolution of discrepancies disclosed by the audit. The Parties should conduct any such audit in accordance with the then most current PASC Joint Venture Audit Protocol.

ii) The Non-Operators would typically have a Non-Operator lead the audit effort in accordance with normal audit processes. This also reflects the practical consideration that the former Operator is often not motivated to pursue an audit diligently. The Parties should determine the desired scope of the audit prior to the audit. The scope will probably be similar to that of a normal J.V. Audit (paid for by the Non-Operators, including the successor Operator). The successor Operator contributes to the cost of the audit because it was a Non-Operator for the period to which the audit pertained.

A successor Operator might also conduct an audit under a Purchase & Sale Agreement with the outgoing Operator as part of its adjustment process if the interest is being acquired through an A&D transaction.

iii) The cost allocation for an inventory conducted under this Clause is consistent with the allocation under the Accounting Procedure.

iv) Item (iv) in the Clause was introduced in the 2015 document to bring clarity to a point that was unclear in prior versions of the document-the interrelationship between the inventory and audit contemplated in this Clause respecting a change in Operator and the ability to conduct the more typical J.V. audit under the Accounting Procedure. Does the change of Operator audit contemplated in this Clause alter in any way the right of a Non-Operator to initiate an audit under the Accounting Procedure? In consultation with PASC, the conclusion was that this audit right should not adversely impact the audit rights under the Accounting Procedure, particularly because of the possibility that Non-Operators might not exercise their right within the prescribed period. There is also an argument that the release language at the end of Clause 2.07 would see the former Operator remaining responsible for audits during its period of ownership as an "outstanding obligation". The independent handling in this Clause was reinforced when looking at the 1981 and 1990 documents because of the sharing of responsibility for costs of the change in Operator audit thereunder (Joint Account charge) vs. the allocation of costs to Non-Operators under the Accounting Procedure audit process. Notwithstanding the greater clarity on this point introduced in the 2015 document, the better practice from an efficiency perspective is to conduct a change of Operator audit for the circumstance in which the new Operator is a Party at arm's length to the former Operator.

v) It can be difficult to resolve audit exceptions in a timely manner, particularly if an Operator has disposed of its interest. The applicable PASC Joint Venture Audit Protocol includes guidelines for resolution of audit exceptions that should be followed insofar as they do not conflict with the Accounting Procedure. Unresolved audit exceptions might ultimately be addressed through arbitration under Clause 21.03 if that Article applies.

Clause 2.09: i) This Clause would only apply if the Operator were proposing its assignee as the successor Operator. It clarifies the rights of the Non-Operators. As there would be no anticipated impact on Joint Operations because of a transfer from ABC Ltd. to its Affiliate, ABC Resources Inc., Operatorship may be assigned to an Affiliate when the Working Interest is also being assigned, and an Operator would typically just note this in the cover letter it uses to distribute the applicable notice of assignment. If the Non-Operators were sufficiently troubled with the Operator's performance, they presumably would have used their other rights to replace it. If there is a concern that the Affiliate is a "shell company," the Parties could easily replace it under Paragraph 2.02B(a) if the Non-Operators hold sufficient interest. They will have immediate access to Clause 2.03 in all cases. Operatorship is to be determined under Clause 2.06 in all other cases.

ii) Suppose ABC Ltd. assigns to its Affiliate, ABC Resources Inc. Since ABC Resources Inc. is a distinct entity from ABC Ltd. and a new Operator, the two-year periods in Clauses 2.03 and 2.04 would start at the effective date of the change without the last sentence.

Clause 3.01 (General): i) The evolution of the role of the Operator to the manager of the Joint Property on behalf of the Parties is apparent by comparing the corresponding provisions in the 1971, 1974, 1981 and 1990 versions of the Operating Procedure.

1971 – "The Operator is hereby delegated the exclusive control and management of the exploration, development and operation of the joint lands for the discovery and production of petroleum substances for the joint account."
1974 – "The Operator is hereby delegated the exclusive control and management of the exploration, development and operation of the joint lands for the joint account."
1981 – "The Operator is hereby delegated the exclusive control and management of the exploration, development and operation of the joint lands for the joint account, provided it shall consult with the Joint-Operators from time to time with respect to decisions to be made for the exploration, development and operation of the joint lands, and keep the Joint-Operators informed with respect to operations planned or conducted for the joint account."
1990 – "The Operator shall consult with the Joint-Operators from time to time with respect to decisions to be made for the exploration, development and operation of the joint lands and the construction, installation and operation of any production facilities, and the Operator shall keep the Joint-Operators informed with respect to operations planned or conducted for the joint account. Subject to the provisions hereof, the Operator is hereby delegated the management of the exploration, development and operation of the joint lands and the construction, installation and operation of any production facilities for the joint account on behalf of the Joint-Operators."

ii) One of the fundamental differences between the conventional CAPL Operating Procedure and Western Canadian production agreements, Canadian frontier agreements, project-based agreements for certain scale sized Canadian shale developments and the typical international agreement is the use of an operating committee to provide direction in those other documents.

Ignoring the Independent Operation mechanism in Article 10.00 and the expenditure approval process, the role of the Non-Operators in setting exploration strategy might seem minimal under the conventional CAPL Operating Procedure. (Subclause 3.01A includes a simple duty to consult, and Clause 5.04 gives a Non-Operator the right to require the Operator to provide the Non-Operators with a forecast of anticipated expenditures over the next 12-month period.) However, it is not feasible to include an operating committee provision in the document. A typical Operator will be operating a multitude of blocks with varying partners, interests, tenures, prospectivity, maturity and activity, and the resultant administrative burden would be high. Moreover, the mechanism would not be workable in many instances anyway because of the likelihood that one Party would hold more than a 50% interest or that there would only be two interest holders. In practice, the Independent Operations Article and the expenditure approval process included in the document provide the Non-Operators with significant control over the exploration and development of the Joint Lands.

Subclause 3.01A: The delegation of management of the Joint Property to the Operator does not impose any obligation on it to initiate or optimize the exploration and development of the Joint Lands, except insofar as the Operator has specific obligations to the contrary under the Agreement. The broad nature of any implied duty of this type might place Operators at risk for the consequences of strategic decisions in which the Non-Operators may have contributed to or caused the outcome by the expenditure approval process. The Non-Operators are always free to promote a more aggressive work program through the Independent Operation process and possibly the replacement of the Operator.

Subclause 3.01B: i) The first sentence was qualified as of the 2015 document to address the possibility that the Parties would include special provisions for the approval of activities respecting the development of Well Pads. It is possible, for example, that Parties involved in a large-scale development program in an area shift from a well-by-well approval to a broader project approval or an annual work program and budget approach. The Parties might also prefer flexibility for the procurement of long lead time equipment required for the conduct of orderly, efficient Operations.

ii) The discretionary authority is included to enable an Operator to make those minor capital expenditures which, in the course of normal day-to-day Operations, are required to maintain production, such as the replacement of a minor piece of wellsite equipment. It is not intended to provide the Operator with the authority to conduct exploration Operations or geological studies. The threshold is a *bona fide* estimated amount linked to the Accounting Procedure limit to reflect a change in the PASC Accounting Procedure, and there is a fallback to $50K if an older form of Accounting Procedure is used. (The corresponding thresholds were $10K in the 1974 document and $25K in the 1981 and 1990 documents.) The Operator's authority to make the expenditure under this Subclause is not compromised if its *bona fide* estimate ended up being too low.

iii) There is no specific requirement for the Operator to submit an itemized report of discretionary expenditures to the Parties, other than insofar as this information is normally required under the PASC Accounting Procedure (e.g., Clause 102 of the 1996 version). The only review mechanism as such would be if a Non-Operator were so concerned by a tendency to make such expenditures that it convened a meeting to discuss the matter.

iv) The Operator may make additional expenditures through an informational AFE without the Non-Operators' approval: (a) for an Abandonment authorized for the Joint Account under Clause 12.01 (including additional informational AFEs for the reclamation and remediation phases, as applicable); (b) if required by the Regulations (e.g., Alberta AER requirements); or (c) if reasonably considered necessary by the Operator for the protection of life, property or the environment. In such event, the Operator is required to advise the Non-Operators of the nature of that requirement or event and the anticipated expenditure associated therewith, with a reasonable level of detail about the applicable program. The overexpenditure requirements of Subclause 3.01C apply to such an informational AFE, and the Operator should advise the other Parties in a timely manner of any developments that it reasonably expects would impact materially the cost, nature or schedule of the applicable program.

Subclause 3.01C: i) This Subclause does not apply to expenditures for which AFE authorization is not required under Subclause 3.01A.

ii) In the absence of a specific provision in an agreement, has a Party that approved an AFE elected to pay its proportionate share of the cost or is its participation conditional on the actual cost corresponding to the estimate? Intuitively, operational logistics lead one to the conclusion that the cost estimate in an AFE is the Operator's *bona fide* estimate of the cost. How could it be otherwise when costs are subject to such factors as mechanical difficulties, the presence of hydrocarbons and weather? One of the consequences of the contrary view would also be that a Party was committed to pay the estimated cost, even if actual costs were lower.

As shown by American cases and the leading Canadian case of Renaissance Resources Ltd. v. Metalore Resources Ltd., [1984] 4 W.W.R. 430 (Alta. Q.B.), affirmed [1985] 4 W.W.R.673 (Alta. C.A.) for the 1974 document, the general legal rule is that AFE approval constitutes authority to conduct the Operation described therein, even though the actual cost may differ from the AFE estimate. One of the Trial Court's *obiter dicta* statements in Renaissance, however, was: "I see no reason why, in the proper case, it would not be open to a joint-operator to allege negligence in the preparation of an AFE and/or the drilling of a well." This qualification was recognized in Erehwon Exploration Ltd. v. Northstar Energy Corp., [1993] A.J. No. 916 (Alta. Q.B.) and Novalta Resources Ltd. v. Ortynsky Exploration Ltd., [1994] A.J. No. 1101 (Alta. Q.B.). It was the main issue in Morrison Petroleums Ltd. v. Phoenix Canada Oil Co., [1997] A.J. No 275 (Alta. Q.B.). The latter pertained to the drilling of a foothills type well in NE British Columbia by an Operator with no experience in that operating environment. The Court determined that the Operator was negligent in the preparation of the AFE because: (a) it did not review the data from offsetting wells for potential drilling problems and drilling schedules when it was generally recognized that there were drilling problems in this area (e.g., shale sloughing, deviation, lost circulation, etc.); and (b) it did not use service companies and personnel with expertise in this operating environment.

Those cases were not addressing the provisions in the post-1990 versions of the document. Clauses 4.01 and 4.02 were modified to require a Non-Operator to satisfy the Gross Negligence or Wilful Misconduct test for claims relating to planning or conducting Joint Operations. An Operator would still also have the potential defence in many circumstances that the Non-Operator's independent ability to use its own expertise to assess the Operation meant that there was no reliance on the accuracy of the cost estimate at the time of the participation decision.

It seems likely, though, that some Parties may choose to amend this Subclause for drilling Operations in the foothills and certain other high-cost areas. Given the potential magnitude of cost overruns in those operating environments, a pure "commitment to the Operation" mechanism could have a serious financial impact on a Party in practice. One possibility for those types of operating environments might be to include a mechanism whereby a Party could elect to become a Non-Participating Party on the same basis as provided for a Deepening under Article 10.00, insofar as costs exceeded a certain negotiated threshold (e.g., 35%, 50%, etc.), subject to the qualification that this right could not be exercised during an emergency or until any existing drilling problems were rectified. Parties are also free to negotiate this type of outcome at the time of the problem.

iii) The corresponding provisions of the previous documents evolved significantly. The 1974 document was silent about overexpenditures. The 1981 document included the following paragraph: "Notwithstanding the foregoing, if the Operator while conducting any single operation for the joint account, incurs or expects to incur expenditures for the joint account in excess of the total amount authorized in writing by the Joint-Operators for that operation plus ten (10%) percent thereof, the Operator shall forthwith so advise the Joint-Operators and submit for their approval a written supplementary authority for such excess expenditures." The 1990 document was changed to require a supplementary AFE for informational purposes only.

The interpretation of the 1981provision was considered in Erehwon, Novalta, Morrison, Duce Oil Ltd. v. Coachlight Resources Ltd., [2000] S.J. No 352 (Sask. C.A.), affirming [1999] S.J. No 12 (Sask. Q.B.) and Powermax Energy Inc. v. Argonauts Group Ltd., [2003] A.J. No. 433 (Alta. Q.B.). There was an *obiter dicta* comment in Erehwon that "a party signing an AFE is bound to pay the resulting costs, at least under the 1981 CAPL, up to a cost overrun of less than 10%." The impact of the 1981 provision was the fundamental issue in Novalta, where the Court interpreted the supplementary AFE obligation as applying only to "operating expenditures", such that the Renaissance test applied to any overexpenditure respecting the drilling and completion of wells. The Court came to the opposite conclusion in Morrison. This was stated to be because of the expert evidence presented to that Court on the issue, where there did not appear to be any expert evidence in Novalta. The Court in Morrison concluded that operation "must be interpreted as applying to all undertakings conducted by the operator for the joint account, including all activities in connection with the drilling of a well except where a contrary intention is expressly indicated in the agreement between the parties". The Court determined that the literal and ordinary meaning of the words required a supplementary AFE for a cost overrun in excess of 110% of the approved amount, notwithstanding that the 1981 document did not specify the consequences of failure to approve the supplementary AFE.

In Duce, the Court agreed with the determination in Morrison, but found on the facts that the operator (Coachlight) had consulted with the non-operator about each significant decision that could increase the cost of the operation and that the non-operator had approved those recommendations. The Court determined that the non-operator could not then refuse to sign the supplementary AFE for the approved activities.

In Powermax, the Court again agreed with Morrison in a situation in which: (a) the final cost of an installation was 2.8 times the original estimate; (b) the Operator made a scope change relative to the installation described in the AFE; and (c) the Operator did not alert the Non-Operators to problems or issue a supplementary AFE until several months after the fact. The Operator also argued that it was inappropriate to allow the Non-Operator to obtain all of the economic benefits of the installed facility without having to share the full cost of the facility, but the Court essentially dismissed the unjust enrichment argument here by noting that the 1981 CAPL Operating Procedure was the juristic reason for that conclusion. (See also United Canso Oil & Gas Ltd. v. Washoe Northern, Inc. (1991), 121 A.R.1 (Alta. Q.B.) and Aber Resources Ltd. v. Winspear Resources Ltd., [2000] B.C.J. No. 742 (B.C. S.C.) with respect to the unjust enrichment issue in the context of a dispute under a resource agreement.)

iv) The initial reaction might be that identification of costs incurred to date in the daily drilling report should eliminate the need for this type of notice. The problem with that view is that information about incurred costs does not provide any insights into why there is an overexpenditure, what is being done to mitigate it and how large the overexpenditure is ultimately expected to be. The provision is based on the premise that an Operator is already sharing the additional information internally with its own management in practice if the overexpenditure is significant.

Subclauses 3.01D&E: i) Subclauses 3.01D and E were added in the 2015 document. They offer functionality that is very useful for both long reach Horizontal Wells typically associated with shale projects and complex foothills wells that commonly see intentional deviations during drilling.

Subclause 3.01D is clear that certain activities to address challenges during drilling are inherent in the approval of a drilling Operation. Subclause 3.01E is always subject to Subclause 3.01D. Subclause E otherwise addresses any potential change in scope argument relating to discretionary changes in the drilling program originally presented by the Operator. In essence, Subclause E creates a "box" that outlines the limits on the Operator's discretionary authority before a Participating Party's consent is required. Subject to any application of Subclause 3.01D, the consent of the Participating Parties to a contemplated modification to the well is required if the condition in any single applicable Paragraph of this Subclause is not satisfied. (This Subclause also governs the Participating Parties' relationship in an Independent Well because of the application of Clause 10.16.)

This Subclause enhances the discretion that was provided for Horizontal Wells under Subclause 8.02B of the 2007 document in two important ways. It offers greater flexibility for long reach Horizontal Wells than the simple 75 metre test in the 2007 document. It also extends the authority to any drilling Operation in which the Operator uses discretion to deviate the well to reflect real time drilling information (e.g., a deep foothills well). However, the discretion granted to the Operator under Subclause 3.01E does not go so far as to provide the Operator with the discretionary authority to plug back and Sidetrack a well, such that Clause 10.08 continues to apply to any such Operation relative to the Participating Parties.

Paragraphs (a)-(e) limit the exercise of the Operator's discretion, with some flexibility for the circumstance in which the well is temporarily being drilled outside of the horizontal target formation (e.g., a thin target formation). However, Paragraphs (f) and (g) potentially offer the Operator additional discretion for Horizontal Wells with a different total measured horizontal length.

ii) Paragraph (f) addresses the total length of a Horizontal Leg, and Paragraph (g) addresses the revised bottom hole coordinates of the well relative to its original bottom hole coordinates. There are two reasons for the inclusion of both of these Paragraphs. Paragraph (f) addresses only Horizontal Wells, while Paragraph (g) addresses both Horizontal Wells and, with a tighter radius limitation, wells that are not Horizontal Wells. The inclusion of both Paragraphs addresses the possibility that a Horizontal Leg could be drilled with bottom hole coordinates within the prescribed limit, but with a greater variance in total measured horizontal length.

The parenthetical reference in each Subclause contemplates that the Parties may agree to a different threshold in conjunction with the approval of a particular well. Although the Operator/Proposing Party may request that incremental discretion in its AFE or Operation Notice, there is nothing in the Subclause that grants it the unilateral authority to impose its preferred discretion on the recipients as a pre-condition to their ability to participate in the well. Any such modification is effectively an amendment to the outcomes in the Operating Procedure. It cannot be imposed unilaterally to reflect the preference of the Operator/Proposing Party.

iii) Subclause 10.02H addresses the corresponding authority to proceed with modifications to the well location before the Non-Participating Party's election rights are potentially triggered under Subclause 10.08C or otherwise at law for a change in scope. It offers greater flexibility to the Participating Parties relative to Non-Participating Parties than Subclause 3.01E.

iv) The onus is on the Parties to assess the suitability of Subclauses 3.01E and 10.02H for their particular circumstances. The Parties will sometimes choose to delete Subclauses 3.01E and 10.02H or to modify the variance thresholds in Paragraphs (f) and (g). The 75-metre radius restriction, for example, may be too narrow with respect to a particular foothills style project. Conversely, the Parties may determine that this Subclause and Subclause 10.02H should be deleted or use a narrower radius if specific well locations are largely driven by seismic data.

Clause 3.03: i) The usual result of a reference to an Operator as an independent contractor would be to require it to assume full legal responsibility for its own negligence. The last sentence is included to minimize the possibility that the Operator could be responsible to the other Parties for ordinary negligence when its accountability for performance is as dictated by Article 4.00 (i.e., Gross Negligence or Wilful Misconduct) and the other provisions of the Agreement (i.e., responsibility for performance of its contractual obligations as Operator).

ii) Subclause B was introduced in the 2007 document to clarify the Operator's rights and obligations for the contracting process. The Operator has a duty to award contracts in accordance with good contracting practices in the oil and gas industry, which would still be the case without this Subclause. The Operator will normally award contracts on a competitive basis, subject to several specified exceptions for which the Operator has greater discretion. They are: (a) non-arm's length arrangements authorized by the Agreement (e.g., Clause 207(b) of the 1996 PASC Accounting Procedure) or the Parties; (b) arm's length *bona fide* alliance arrangements with terms that are not unreasonable; (c) the use of local suppliers as required by the Regulations or the Title Documents or in accordance with the Operator's normal contracting policy; or (d) contracts below a specified threshold, where the threshold could easily be modified. The provision was included largely because of the increased use of alliances with suppliers and the increased emphasis on the use of local suppliers for miscellaneous project support, particularly in northern Alberta, B.C. and Canada's northern territories.

iii) The document does not address the specific expectations for supply contracts. Their complexity will vary greatly. The contract for a one-time sale of supplies FOB the supplier's warehouse would tend to be much simpler than a contract under which goods or services are supplied on an ongoing basis on location over the life of the Operation. Supply arrangements could, if appropriate in the context of the particular contract, include such provisions as those requiring the contractor to: (a) carry insurance; (b) comply with the Operator's HSE and drug and alcohol policies; (c) maintain supporting accounting records and allow an audit; (d) comply with the Regulations and any Operator policy for use of local suppliers or the employment of community members; and (e) include similar provisions in its contracts with subcontractors.

Clause 3.04: i) The interrelationship between this Clause and Article 4.00 has historically been unclear. Is an Operator responsible for a loss suffered by the Parties if it has not conducted an Operation in accordance with good oilfield practice, but its performance could not be characterized as Gross Negligence or Wilful Misconduct? This issue was addressed in Erehwon and Morrison, in which the Courts reviewed the issue in the context of the 1981 CAPL Operating Procedure. In those cases, the Courts determined that the limitation in the version of Clause 4.02 in that document did not preclude the Operator from being responsible to the Non-Operators for losses suffered by them as a result of the Operator's breach of contract under another provision. The Morrison case was specifically in the context of the good oilfield practice obligation. It was unclear if the Court would have made a similar finding about the interrelationship of Clauses 304 and 401 in the 1990 document because of the "Notwithstanding" reference in Clause 401 of that document. (This risk is lessened significantly after Adeco, as the Court of Appeal recognized that the purpose of that reference was to ensure that the Gross Negligence or Wilful Misconduct test was applicable to breaches of Clauses 303 and 304 of that document.) The corresponding provisions of the 2007 document had been modified in advance of Adeco, to provide greater protection for Operators on this issue. The provision expresses more clearly the intention to apply the Clause 4.02 Gross Negligence or Wilful Misconduct test if Non-Operators seek damages for losses they suffer as a result of the manner in which Joint Operations are conducted under Clause 3.04. (See also the annotations on Clause 4.01.)

ii) There is a general obligation to manage a reservoir in accordance with appropriate reservoir management and conservation principles. An Operator that uses its position to reduce production volumes below productive capacity to produce higher interest equity wells in a competitive drainage situation, for example, is potentially open to litigation and removal from its position as Operator. (An Operator that chooses not to produce an economic well without good reasons is also vulnerable under the Clause 2.03 challenge process, as the proposal under the Challenge Notice might just be to produce the well.)

iii) One of the questions that arises during periods of low commodity prices is the ability of an Operator to shut in a well. Whatever ambiguity may exist with respect to this issue, there is one thing that is clear-the words of the Operating Procedure do not expressly provide an Operator with a unilateral right to shut in wells or facilities whenever it suits the Operator to do so.

The Operator has an overriding duty (i.e., Clause 5.01) to manage the Joint Property for the collective benefit of the Working Interest owners. One might attempt to argue that there is an inherent duty on an Operator to attempt to produce a well that is clearly capable of production in Paying Quantities when it is able to do so (i.e., no facilities or pipeline constraints that are complicating the ability to produce).

An Operator that chooses to shut in a well capable of production in Paying Quantities arbitrarily could potentially be open to a claim from the adversely impacted Parties (e.g., those with attractive hedges, take or pay transportation commitments, bank covenants, a unique vulnerability because of a small number of wells, risk if the well cannot later be reactivated, etc.). It also potentially introduces a risk of replacement as Operator under the default or no cause replacement mechanisms in Subclause 2.02B or the Clause 2.03 challenge process. The Operator also needs to be cognizant of the potential resultant negative impact on the relationship with the other impacted Parties with respect to this property and in the broader sense.

An Operator considering this issue must also remember that the expenditure limitation provisions in Clause 3.01 potentially limit the Operator's ability to charge to the Joint Account any costs to suspend the well and any associated reactivation costs.

The problem when considering this issue, of course, is the circumstance in which the affected Parties have very different economic outcomes, often because of different infrastructure positions.

The preferred path for any Party that wishes to shut in a producing well is to negotiate that outcome with the other Working Interest owners to try to obtain the highest possible level of consensus to shut in the well. While unanimity on this issue is undoubtedly preferred, it will not always be possible. There may be circumstances in which the Operator may need to assess the legal risks relative to the benefits that it could obtain by proceeding to shut in the well, if for example, there is a high level of Working Interest support to shut in the well.

Clause 3.05: This Clause was introduced in the 2007 document because of the increasing emphasis on health, safety and the environment in recent years. This is demonstrated by the introduction of Regulations such as the Alberta Occupational Health and Safety Code and recent changes to the federal Criminal Code creating criminal sanctions around existing provincial occupational health and safety laws, by requiring all organizations (including directors, employees, agents and contractors of such organizations) to take "reasonable steps" to provide a safe workplace for their workers. The expectations in this Clause address many of the elements in 2002 guidelines prepared for international agreements by the International Petroleum Industry Environmental Conservation Association and the International Association of Oil & Gas Producers.

Subclause 3.05A: i) This Subclause imposes a duty with respect to HSE that is similar to the general good oilfield practice requirement in Clause 3.04. As with that Clause, the Operator is only liable for Losses and Liabilities suffered by the other Parties as a result of its breach of Clause 3.05 if its conduct meets the "Gross Negligence or Wilful Misconduct" test in Clause 4.02. An Operator with HSE deficiencies is potentially subject to replacement under Subclauses 2.02A and B. It is not feasible to include any numerical test for HSE deficiencies here because of the varying emphasis on HSE measurement tools in industry. However, like-minded Parties might sometimes choose to include a custom provision.

ii) The provision includes a general requirement to have internal processes in place to address any potential emergency. Not having such processes in place severely limits the ability of an Operator to mitigate the impact of an emergency. This can have serious consequences on safety, property and the environment, as well as major impacts on costs and reputation.

iii) The provision includes a general requirement to have work rules that restrict or prohibit possession or use of alcohol, illicit drugs and other controlled substances and weapons at the location of Joint Operations. This is an attempt to balance the desire of the Non-Operators to minimize safety risks with the desire of Operators not to be micro-managed in the manner in which they conduct Operations. This also recognizes that some Operators may not have any policy respecting the control of drugs and alcohol in addition to the requirements in this Subclause.

Some Parties will also have detailed internal policies with which they are required to comply. Some policies contemplate the ability to conduct unannounced searches, typically subject to a qualification that they are subject to the Regulations or other applicable law, which would include the Canadian Charter of Rights. Some Parties will require the inclusion of a more specific Clause about this area because of their internal policies.

iv) While not addressed in the provision, the emission of greenhouse gases is a major emerging issue. It was not addressed specifically because the Regulations and industry processes and guidelines in this area are evolving (e.g., CAPP voluntary emissions targets and guidelines).

Subclause 3.05B: The Operator is to notify the other Parties of any significant HSE incident promptly. The Operator will consult with them as appropriate in the circumstances.

Subclauses 3.05C-E: i) Subclause C creates a duty to conduct periodic inspections and audits for wells and Production Facilities held as Joint Property. This provision has been structured to link the review frequency and criteria to risk by providing the Operator with the discretion to choose audit criteria, personnel and an appropriate frequency, recognizing that the Regulations may prescribe a shorter frequency. HSE audits typically involve a structured review of HSE management systems, and do not necessarily involve an audit of each well and Production Facility. Subclause D addresses the report and the management of deficiencies. Subclause E includes Non-Operator audit rights.

There is no duty on an auditing Non-Operator to share its report with Non-Operators that did not participate in the review, as the provision of the report would reward them for not participating. However, a Non-Operator that had identified significant deficiencies in its review would probably provide a copy of the report (or extracts therefrom) to the other Non-Operators to make them aware of the magnitude of the issue. This is particularly the case if the Non-Operators are considering a removal of the Operator.

ii) The provision does not specifically address the consequences if there are major concerns arising from the audit process. Ultimately, the Non-Operators would probably consider the replacement of the Operator if there were major deficiencies that were not being addressed. As a minimum, the replacement process provides a strong potential motivation to the Operator to be more vigilant in addressing deficiencies.

Subclause 3.05F: This Subclause has been included to mitigate the possibility of prosecution of the Non-Operators under the Regulations for failure to be proactive in assessing and addressing an Operator's HSE performance deficiencies.

Clause 3.07: i) References to internal controls were introduced in the 2007 document because of the increased regulatory requirements respecting financial reporting and internal controls (i.e., U.S. Sarbanes Oxley Act) after the Enron investigation.

ii) Although the provision does not specifically refer to microfiche, microfilm and other electronic records, the phrase "records and accounts" is broad enough to include records in those forms. Since auditors would have access to the records in whichever form they are maintained, it is inappropriate to specify an Operator's record keeping procedures in the document.

iii) Clause 5.01 requires the Operator to maintain records for Operations conducted hereunder, so that they can be accessed separately from those kept by it for other Operations, in accordance with good oilfield practice.

Clause 3.08: i) The proviso was introduced in the 2007 document. It was included primarily to address the HSE issues associated with site visits.

ii) The reference to confidentiality of information reflects two considerations. The first is the fact that there will sometimes be restricted access to wells that the Parties have designated as "tight holes", although this would not otherwise affect a Party's access to well information under Article 7.00. The second is that the increased frequency of the use of Well Pads will see Operators implementing site restrictions to prevent a Party from having access to wells in which it has no interest at the relevant time (i.e., a Non-Participating Party or a Party that has yet to elect).

iii) The Operator may be providing proprietary processes, techniques or knowledge of significant competitive advantage to support Operations, particularly with respect to shale drilling and Completion programs. There may be circumstances in which the Operator is sufficiently concerned about the erosion of its competitive advantage that it may wish to modify the Clause to add something such as "proprietary processes, techniques or information of the Operator or any of its Affiliates," after "HSE," in the 7th line of the Clause.

Operators considering this type of modification should remember that Non-Operators would often object to it. This is because they are paying their share of the cost of the Operation and because of their desire in many cases to learn from an Operator that has a different range of experience or uses a different approach.

Clause 3.09: i) Surface rights or regulatory licences or approvals associated with Joint Operations are acquired, maintained and managed for the Joint Account. In the absence of a subsequent agreement affecting the surface rights, such as a unit, they are held under the Operating Procedure, since it is the contractual basis for charges and credits for surface rights held as Joint Property. The inclusion of the "manage" reference in the 2007 document reinforced the Operator's authority to enter into road use, crossing and similar operational agreements in the normal course of business, subject to the general good oilfield practice requirement in Clause 3.04.

Nexen Inc. v. Fort Energy Corp., [2007] A.J. No. 1202 (Alta. Q.B.) considered the rights of a Non-Operator with respect to surface rights held by the Operator for the Joint Account in the context of the 1990 document. The Court found that a Party conducting an Independent Operation was entitled to an assignment of the applicable surface rights held for the Joint Account to conduct that Operation and that the scope of the reference to records in Clause 3.07 includes the documents under which the surface rights are held. The Court also determined that the Non-Operator was not entitled to an assignment of the surface rights to facilitate the conduct of operations under a different agreement.

The shared use of surface rights is an issue of increasing importance, given the desire to mitigate the environmental footprint and to optimize cost synergies. The Parties/owners would preferably enter into a pad site sharing agreement to address the broad range of issues inherent with a Well Pad sharing arrangement and the construction of the associated surface infrastructure. (See, for example, the definition of Well Pad and the modifications to Subclause 10.04 introduced in the 2015 document.)

ii) The most common credits for the surface rights would be fees from road use agreements granted to third parties. Another that could be significant relates to fees for use of joint roads for the Operator's own operations, something which Operators may forget to monitor.

iii) The document recognizes that the requirement for community and stakeholder consultation is an increasingly critical component of project planning and implementation, and is an area that is evolving rapidly. The Regulations in this area are often "guidelines" (e.g., Alberta's Directive-56), so compliance with the standards outlined in the guidelines will not necessarily be sufficient. Operators need to consider if additional community and stakeholder consultation is required for each particular Operation. The definitions of Drilling Costs and Equipping Costs were modified in the 2007 document to recognize expressly the incremental costs associated with the consultation process. Those costs should be included in the relevant AFE, and would otherwise be subject to the expenditure limitation in Subclause 3.01B.

iv) A dispute about an allocation of costs between a Joint Operation and another operation would relate to an audit exception. Any dispute about an audit exception is potentially within the scope of the Article 21.00 dispute resolution process. Arbitration could ultimately be used to resolve it.

v) This Clause and the financial authority in Paragraph 3.01B(b) do not allow an Operator to charge the Joint Account any fees or deposits required by the Regulations as a condition of that particular Operator holding a licence or approval (e.g., LLR deposits in Alberta). This ultimately reflects the fact that the requirement to submit a LLR deposit is linked at this time to the Operator's own particular financial circumstances. Any suggestion that any required LLR deposit be linked to the Participating Interests in the well would see very different outcomes when a large, financially viable company were the Operator relative to a small company with a lesser asset base, when the outcomes to Non-Operators should be consistent. That being said, there may be circumstances in which the similarities in financial status of the members of a particular project group are such that they may agree in their particular Agreement to override this restriction and share responsibility for any such fees or deposits in proportion to their respective Participating Interests in the applicable well. The onus is on the Parties to modify the document if it does not present an appropriate outcome for them.

Subclause 3.10A: i) The Operating Procedure has historically presumed that the Operator is also the representative for land administration matters with the lessor. As this is not necessarily the case, the definition of Title Administrator was added in the 2007 document, even though the Operator and the Title Administrator will typically be the same Party.

The Parties must consider three key points when reviewing this issue. They must understand who will have this responsibility if it is not the Operator, and should document this in the Head Agreement or the Land Schedule. They need to recall that it will often be beneficial to allow another Party with better information to make a continuation application. The Parties should also consider if anything has changed for a Title Document not administered by the Operator whereby the Operator should assume that role. One of the more common examples of the latter is the situation in which a farmor has administered Title Documents because of the initial retention of since expired deep rights.

As noted in the annotations on the definition of Title Administrator, clarity in expectations is particularly important if a Title Document is being maintained by an entity that is not a Working Interest owner. Clarity of expectations is also very important in a non-cross-conveyed pooling because loss of a contributed lease would typically see less than a complete Spacing Unit being held and loss of the right to produce the well. The loss of tenure in the Trident case referred to in the annotations on the definition of Gross Negligence or Wilful Misconduct was ultimately attributable to confusion that was inadvertently created with respect to the responsibility for communication to the lessor.

ii) The Parties need to address clearly their expectations for the handling of lessor royalties and encumbrances in their pooling agreements. This is particularly important for non-cross-conveyed poolings.

iii) The duty to maintain the Title Documents does not require or permit the Title Administrator to drill a well or conduct any Operation.

iv) A growing issue associated with the increased stratification of rights is the allocation of portions of mineral rentals to the interest holders in various horizons. While it is mutually beneficial for the affected Parties to be clear about the expectations in this area (i.e., side letter between land administrators of affected Parties), the issue is beyond the scope of the Operating Procedure.

v) The Title Administrator's rights include the default provisions in Clause 5.05 and the reimbursement mechanism in Clause 5.06.

vi) The last sentence was included to provide a Title Administrator with greater protection if it inadvertently allowed a Title Document to lapse. The risk is of particular concern for freehold leases, especially since the loss may be due to an error in the head office or in the field (i.e., suspending a well).

Subclause 3.10B: i) The Title Administrator is to consult about any continuation or grouping applications it proposes to make to maintain any Title Documents in good standing and such other matters as offset requirements and the payment of compensatory royalties. It is required to provide copies of related correspondence to the other Parties in a timely manner, excepting any data to which they are not entitled. The provision applies on the same basis to an Operator or another Party making an application under the Regulations to modify a Spacing Unit or increase drilling density.

(See also Subclause 10.02A about the response to an Operation Notice when an application of this type is outstanding.)

As noted in the annotations on the previous Subclause, it will often be advantageous to authorize another Party to make an application because it has additional information to which the other Parties do not have access.

ii) If the Operator is not the Title Administrator, it will probably still offer leadership in the matters contemplated in this Subclause.

Subclause 3.10C: i) This mechanism is designed for the situation in which the interests in the affected lands are uniform. It can be used for the scenario in which a farmee has earned all of the licence lands for drilling a well that validated less than an entire licence.

It will sometimes be preferable to include a land selection provision in the Head Agreement that overrides this Subclause. A farmor would likely want to include a special provision if a land selection is required during the earning phase. This could be the case if sufficient work had previously been conducted to enable the Parties to make a selection on a portion of the licence lands.

In addition, a special provision would be required if a farmee had both earned and validated less than the entire Title Document, as the process would be much more complicated.

As the provision also assumes that the Parties' interests would be consistent throughout the Title Document, modifications would be required if there were different farmors in distinct portions of the licence or if farmor interests varied.

ii) Assume that there were three Parties with Working Interests of A50%, B30% and C20% and the Parties could select 10 selection units in their land selection as a result of a well drilled for the Joint Account. Each Party would select units in proportion to the Working Interests, being respectively five, three and two selection units. The order of the 10 individual selections would be chosen randomly (e.g., picking order out of a hat), such that A's five selections are not necessarily sequential.

iii) Suppose that the Working Interests were A 60%, B30% and C10% and the Parties had nine remaining selection units to complete their land selection. The calculated entitlements for the Parties would be 5.4, 2.7 and 0.9 selection units respectively. A and B would initially select seven selection units in a unit-by-unit sequence determined by draw, such that the remaining partial entitlements would be C 0.9, B 0.7 and A 0.4. C and B would then, in that order, use their partial entitlements to complete the selection of the remaining two selection units.

iv) Assume that the land selection is because of an Independent Well drilled only by A. Subclause 17.01B provides that the entitlements would accrue solely to A, subject to the requirement that they be applied firstly to the Joint Lands.

Subclause 3.10D: i) This Subclause is designed for the situation in which sufficient work has been conducted to validate only a portion of the lands contained in a Title Document and an expiry is approaching. There is a problem determining if a well is a Title Preserving Well and the applicable Preserved Lands for the purpose of Clause 10.10, unless the lands to be retained for the Joint Account are designated prior to issuance of the Operation Notice. As a result, a provision similar to this Subclause was introduced in the 1990 document. The 1990 document, though, included a 12-month period, which was reduced to six months in the 2007 document.

If a Party were concerned that the lands it regarded as prospective would be returned to the Crown unless an additional well were drilled, it could require the Parties to make their land selection at an early date for the purposes only of crystallizing their positions under Clause 10.10. If the lands it regarded as prospective were selected, the cost recovery in Clause 10.07 would apply to a well thereon. If, on the other hand, they were not selected, the penalty in Clause 10.10 would apply to a well thereon.

ii) Since the land selection would not be sent to the Crown until the date required by the Regulations, the Parties would retain the flexibility of changing their selection at a later date should they so agree.

Subclause 3.10E: This Subclause was introduced in the 2007 document, and provides clarity about the outcomes if a Party chooses not to participate in an extension of the applicable Title Document (i.e., Alberta Section 17 extension under penalty, B.C. drilling licence extension, B.C. Section 62 extension under penalty for 10-year leases). It basically creates a quasi-surrender process associated with continuation fees, extension fees, penalty payments, compensatory royalties and similar special payments that are required to maintain any portion of the Joint Lands in good standing. In essence, a Party that chooses not to pay its share of any such amount will forfeit its entire Working Interest in the applicable portion of the Joint Lands. The surrender process in Clause 11.03 would then apply on a *mutatis mutandis* basis.

The retaining Parties will assume responsibility for the forfeited Working Interest (and acquire it) in proportion to their Working Interests unless they agree to a different allocation.

Subclause 3.11B: i) The Operator will obtain and maintain for the Joint Account all insurance policies and other forms of financial responsibility required under the Regulations. The requirement will not apply insofar as the Parties can otherwise collectively or individually satisfy it.

ii) The Operator is not required to confirm if a Party that represents it satisfies the requirement actually does so. The other Parties could pursue any Losses and Liabilities suffered by them if the other Party misrepresented its satisfaction of the requirement.

Alternate 3.11C(a): i) Policies must be maintained with reputable insurance companies.

ii) Policies are maintained "for the benefit of the Parties and their respective directors, officers and employees". It is the better practice for the Operator to have the policies endorsed to add these persons with respect to the specific work, to ensure that all of those involved with the Operation will have the protection of the policies.

iii) There is no obligation to obtain "control of well insurance" in either this Alternate or Alternate C(b). This coverage can be expensive, and any such coverage is typically required on an individual basis. In any event, it is not a good use of funds in low-risk operating environments. There may be unique circumstances in which the Parties consider obtaining this coverage jointly if there are special risks. However, this should only be considered with the full involvement of insurance experts.

iv) A "not less than" reference is not used in the Subparagraphs describing the policies. The inclusion of this type of reference would have provided the Operator with total discretion for the selection of the additional coverage to be charged to the Joint Account.

v) The Alternate does not include a mechanism whereby the Operator may cover the Joint Account risks under the umbrella policy and charge the Joint Account an amount approximating that for which that insurance would have otherwise been obtained in the marketplace. The main reason for not including the mechanism is that applicable statutes state that only a licenced insurer is permitted to charge an insurance premium. In addition, the appropriateness of such a mechanism would depend on the particular fact situation. The Non-Operators would consider their past dealings with the Operator and their perceptions about the Operator's continued financial viability. They would also require a mechanism whereby the option could be terminated, to address their concerns respecting a change in Operator or a change in the Operator's financial position.

vi) The limits in the 2007 document were raised significantly, and Parties may wish to revise them for their particular circumstances (i.e., higher risk operating areas). The corresponding limits in the 1974 document were: $500K, $500K and $1MM respectively. The corresponding limits in the 1981 document were: $1MM, $1MM and $2MM respectively. The corresponding limits in the 1990 document were: $1MM, $1MM and $5MM respectively.

vii) The Parties may choose to acquire additional policies for the Joint Account in a particular transaction. This should only be done with the full involvement of risk management personnel and with clear documentation that is distributed to the applicable internal stakeholders.

Alternate 3.11C(b): i) Except for policies required to be maintained under the Regulations (Subclause 3.11B) and the special allocations of legal responsibility under Article 4.00, each Party is responsible for losses applicable to its Working Interest. Agreements increasingly include an obligation on Parties to carry control of well insurance individually for their Working Interest share of costs. A provision was not included in the document because of the variance in these provisions and the degree to which they are customized to reflect the risks associated with the particular circumstance (property risk and Party risk). Parties including such a provision should be clear about the interrelationship between their provision and the other obligations in this Clause.

ii) Notwithstanding the general statement that each Party is to be responsible for the losses or claims applicable to its interest, the provision may not be effective against third party litigants. A Court is not obligated by the provisions of the Agreement. Unless the Court apportions legal responsibility among defendants, a successful plaintiff can enforce its judgment jointly against the defendants that were held responsible for its loss.

Subclause 3.11D: The conditions in Paragraphs (a)-(d) apply to Subclause 3.11B and any Joint Account policies maintained under Subclause 3.11C.

Paragraph 3.11D(a): Without the reference to deductibles, the Operator could maintain the required coverage, but include deductibles which were so large that the coverage would provide only minimal protection. The deductible limit is aligned to the applicable expenditure threshold under Subclause 3.01B. Larger deductibles can be carried with the Parties' prior approval.

Paragraph 3.11D(b): i) The Operator is required to notify the other Parties if the specified policies or coverages are, in the Operator's reasonable opinion, unavailable or available only at an unreasonable cost. If this occurs, the Parties may wish to redetermine the policies and coverages to be maintained for the Joint Account.

ii) Insurance policies contain items, conditions or exclusions that limit the risks covered by the policy or the circumstances under which the insurer would be obligated to pay. These provisions should be reasonable, and the Operator is required to obtain the Parties' consent if it proposes to make such a change during the term after the policy or policy renewal has been acquired.

Paragraph 3.11D(c): Payments made by the Operator for losses or claims arising out of Joint Operations are initially charged to the Joint Account <u>if</u> the payment has been authorized by the applicable insurers or is otherwise authorized. There are two points to note about this provision.

Firstly, it is inappropriate to authorize the Operator to settle claims in advance of obtaining insurance proceeds or a settlement agreement from the insurer, unless the claim will not be covered by insurance or falls within the deductible limits thereof. This action could preclude payment by the insurer if it had not been given proper notice of a potential claim prior to the Operator's settlement or if it did not agree with the settlement terms.

Secondly, losses are initially assumed to be for the Joint Account. Insofar as it is determined that they are not to be borne for the Joint Account under Article 4.00, the accounts of the Parties will be adjusted at the time of that determination, which is likely to be significantly after the payments have been made. Without that reference, it is likely that there would be a dispute as to the timing of the adjustment.

The Operator must attempt to process those claims diligently. It will promptly credit the Joint Account the amount it ultimately recovers.

Paragraph 3.11D(d): i) Note the reference to primary coverage and exposure to a deductible. As many Non-Operators will carry other insurance, this is included to ensure that the insurers of the Joint Account coverage will be prevented from claiming that other coverage may be available to share the loss. If a Non-Operator carries separate coverage to reduce its exposure to a deductible, it should ensure that its policy is structured so that it applies only for the deductible portion of the loss and does not duplicate the Joint Account coverage above the deductible amount.

ii) Policies are to survive the default or bankruptcy of the insured for claims arising out of an event prior to the default or bankruptcy. The insurer should not be able to deny claims, for example, simply because the insured may no longer be a legal entity.

Subclause 3.11E: i) There may be special circumstances in which some or all of the Parties are individually required to obtain "control of well insurance" for their own account, where this would require a modification to this Subclause. The amount of any such policy should be based on the perceived risk for the particular operating area (i.e., a foothills sour gas well has a very different risk profile than a typical medium depth well).

Given that this coverage is expensive and that some larger companies may prefer to self insure this risk, some companies object to a specific requirement to obtain a policy of this type. One potential approach to consider in this circumstance is the inclusion of language through which the obligation is waived for a particular Party and any of its Affiliates. This might be done by adding something like the following in the obligation: "…, provided that this obligation will be waived for X and Y and any of their respective Affiliates that become Parties, but not for any other successor in interest of X or Y without the consent of the Parties."

ii) A Party will ensure that the policies maintained by it under this Clause include waivers of subrogation.

Once a claim settlement is made by an insurer, it has the right to attempt to recover from the third parties who have contributed to the loss, a concept referred to as subrogation. By placing a waiver of subrogation in the policy, the insurer agrees in advance not to take action against the beneficiaries of the waiver, being the Parties and their respective directors, officers and employees. Unless that class is otherwise protected under the policy (i.e., by being named insureds), members of the class that contribute to the loss are at risk without the waiver.

Subclause 3.11F: The Operator is required to provide a reasonable level of assistance to Non-Operators processing claims. The Operator would probably expect to be compensated for extra effort associated with labour intensive special requests for information from a Non-Operator.

Subclause 3.11G: Operators should not take the responsibilities prescribed by this Subclause lightly. If the contractors or subcontractors cause a loss in circumstances in which their insurance coverage is inadequate and they do not have the financial resources to withstand the loss, the responsibility for the loss may ultimately rest with the Parties. Also, note the requirement that those policies include waivers of subrogation.

Subclause 3.11H: There may be special circumstances in which the Operator might request proof of compliance from a Non-Operator. This would tend to be in situations with high operational risk, where there are some concerns about the financial viability of that Party in the event of loss.

Clause 3.12: The "insofar as" reference at the end of the first sentence was added in the 2007 document because Petrinex (and any similar process for jurisdictions other than Alberta and Saskatchewan) may allow Non-Operators independent access to this information in due course.

Clause 3.13: This Clause has traditionally excluded freehold mineral tax, but was modified in the 2007 document. This reflects the fact that Operators often pay the applicable share of freehold mineral tax and invoice each applicable Working Interest owner and lessor for its respective share of the amount if the Operator is the lessee. Parties would need to coordinate responsibility for freehold mineral tax in their particular circumstances if the Operator is not the lessee and declines to assume this responsibility or the Regulations dictate another approach. They also need to be aware of any notice requirements under the Regulations resulting from a change of interest.

Clause 3.14: This Clause has been included so that there is a specific duty to test the accuracy of metering equipment. While a bigger issue in the context of gas plants covered by a CO&O agreement, this can still be an issue for any wellsite measurement. Rather than include detailed measurement provisions, such as those included in Article VII of the Operating Procedure included in the 1999 PJVA CO&O Agreement, the Clause applies the PJVA resolution methodologies if the applicable Accounting Procedure does not address the issue. (While Accounting Procedures have not historically addressed this issue, the inclusion of the reference accommodates any future changes in this area.) In practice, any adjustment would be on a cash or volume makeup basis, as agreed by the Parties at the time.

Clause 4.01: i) The breach of contract reference is included in Clause 4.01 because of Erehwon Exploration Ltd. v. Northstar Energy Corp., [1994] A.J. No. 916 (Alta. Q.B.). One of the arguments raised by the defendant about an accounting issue under the 1981 document was that all liabilities would be for the joint account unless the gross negligence test in Clause 401 of that document was satisfied. The Trial Judge's response to that suggestion was: "However, most importantly, I reject the suggestion that Article IV was meant to relate to the standard of care applicable to the relations between the CAPL parties themselves, and in particular to the Operator's duty to the Non-Operators in carrying out joint operations. In my opinion, Article IV is more likely intended to deal with third party losses." This approach was also endorsed in a breach of good oilfield practice context in Morrison Petroleums Ltd. v. Phoenix Canada Oil Co., [1997] A.J. No. 275 (Alta. Q.B.).

It is unclear if the same interpretation would apply to the 1990 document. Clause 401 of the 1990 document was modified significantly from the 1981 version, and included a reference to losses "respecting any person", which would include both third parties and the Parties.

The 1990 document arguably would have provided the same result with respect to accounting charges in contravention of the agreement, as in Erehwon. The gross negligence test might have applied to the Morrison good oilfield practice scenario, though. The inclusion of the "notwithstanding" reference respecting Clauses 303 and 304 at the beginning of Clause 401 of the 1990 document was intended to ensure the Clause 401 gross negligence test had to be satisfied for claims made under those Clauses. As shown by the annotations to Clause 401 of the 1990 document, there was no attempt to limit a party's right to the remedies available for the Operator's breach of its other contractual obligations to the Parties.

The interrelationship between Article 4.00 and the breach of the Operator's contractual obligations was further clarified in the 2007 document because of Erehwon and Morrison. The reference to losses "respecting any person" in the definition of Losses and Liabilities refers expressly to the Parties. A claim for breach of Clause 3.04 and Subclauses 3.05A and 3.10A requires liability under Article 4.00 because of the operational nature of those obligations and the potential magnitude of the loss. Clauses 4.01 and 4.02 also include a reference to the "planning" of Operations, to clarify the expectations for the planning of a Joint Operation, including preparation of the associated AFE.

That being said, there is uncertainty respecting this issue under the 1990 document after the Adeco decision. The issue in that case was the responsibility of the Operator to the Non-Operators in a situation in which the Operator made serious errors in the management of a continuation application and failed to retain lands that should have been continued. The Court ultimately found that the Operator's conduct constituted gross negligence under the 1990 document, while confirming that the "Notwithstanding" reference at the beginning of Clause 401 applied the higher gross negligence standard to breaches of Clauses 303 and 304 of that document. In the context of the Court's interpretation of "joint operations" in that document, the Court also concluded that the effect of Clause 401 of the 1990 document was that the Operator would typically only ever be solely responsible for losses that fell within the scope of the gross negligence test therein. (See also the annotations on the definition of Operation.)

The weight to be given to that particular aspect of the judgment over time with respect to the 1990 document is unclear. The Court's finding that the Operator's conduct constituted gross negligence was such that the additional comments were not actually necessary for the determination of the case.

Taken literally, this aspect of the judgment would potentially mean that a Non-Operator seeking recovery of funds for breach of the Accounting Procedure or for misappropriation of funds under Clause 507 of the 1990 document, for example, would have to prove that the Operator's conduct constituted gross negligence or wilful misconduct in order to be successful in recovering funds properly belonging to it. As noted in the last paragraph of this annotation, this issue is addressed expressly in the post-1990 versions of the document. These documents allow a Non-Operator to pursue traditional legal remedies for breach of contract, other than for the specific Clauses and Subclauses identified in Paragraph 4.02(b) for which the Gross Negligence or Wilful Misconduct standard applies. As a result, a Non-Operator seeking recovery of funds it alleges belong to it (versus damages suffered as a result of a field event, for example) under the post-1990 documents is required to prove only that the amounts are owing to it in contract without having to prove that the Operator retained them because of its Gross Negligence or Wilful Misconduct.

ii) Clauses 4.01 and 4.02 also reflect the Erehwon case. Other than for Clause 3.04 and Subclauses 3.05A and 3.10A, the Operator retains responsibility for breaches of its contractual obligations without regard to Article 4.00. These other contractual obligations pertain to such matters as breach of the Accounting Procedure and misappropriation of funds held under Clause 5.07. While much clearer than previous versions of the document, the Operator's responsibility for those breaches has not been increased. The Extraordinary Damages exclusion in Clause 4.04 actually provides it with more protection than it has for breach of contract under pre-2007 versions of the document.

iii) The special outcomes in Clause 4.02 apply to the Operator in the performance of its responsibilities as Operator. The Article does not alter the rights and obligations of the Operator as a Party.

iv) The Clause provides some protection to persons who are not Parties. Greenwood Shopping Plaza Ltd. v. Beattie et al (1980), 111 D.L.R. (3rd) 257 (S.C.C.) held that someone who is not party to a contract can neither sue nor rely upon it to avoid liability, except in case of agency or trust. London Drugs Ltd. v. Kuehne & Nagel International Ltd., [1993] 1 W.W.R. 1 (S.C.C.) later determined that an employee could rely on a limitation of liability provision under a contract to which it was not privy if: (a) the provision purported to extend the protection expressly or implicitly; and (b) the employee was acting in the course of the employment and performing the services provided for under the contract when the loss occurred.

v) A reference to directors and officers has been included because of the tendency of American suits to cast a wider liability net.

vi) Agents and consultants were excluded from the "protected class" as of the 2007 document, even though they continue to be identified in the class of actors that can trigger a loss to which this Article applies. The conclusion when preparing that document was that they should not have the benefit of the broad indemnification granted to the Operator. The Operator's contract with them will include insurance and liability and indemnification provisions that address the allocation of responsibility for loss. It is important for the Operator to ensure that it does not have contracts in place with its consultants and agents that are deficient in this area. Without suitable protections, the Operator faces a risk that it could be brought into an action against its consultants and agents as a third party or via subrogation. (Also see Subclause 3.11G.)

vii) The Operator is also a Working Interest owner as a Party. The indemnification obligation is not borne only by the Non-Operators.

Clause 4.02: i) Note the reference "whether negligent or otherwise". There is a risk that an Operator would remain solely responsible for its own negligence unless this exclusion is included. As a general rule, one has to contract out of responsibility for one's own negligence specifically.

ii) A provision might be held to be only an obligation to indemnify if the distinction between liability and indemnity is blurred. In such event, the provision might not provide them with a remedy for direct damage to their property. See Mobil Oil Canada, Ltd. v. Beta Well Service Ltd. (1974), 43 D.L.R. (3rd) 745 (Alta. S.C., App. Div). Recent decisions, however, indicate that Courts are willing to look at the wording in its context. See, for example, TransCanada Pipelines v. Potter Station Power Ltd., [2002] O.J. No. 429 (Ont. S.C.), affirmed [2003] O.J. No. 1879 (Ont. C.A.), Alberta v. Western Irrigation District, [2002] A.J. No. 1085 (Alta. C.A.) and Herron v. Chase Manufacturers Inc., [2003] A.J. No. 865 (Alta. C.A.).

iii) Note the "insofar as" reference. This ensures that a loss which is due to the Operator's Gross Negligence or Wilful Misconduct and other causes outside the scope of Clause 4.02 can be apportioned between the applicable causes. It also enables the Operator to raise the issue of contributory negligence if the acts or omissions of the injured Party contributed to its Losses and Liabilities.

iv) Paragraph (b) was introduced in the 2007 document. Clauses 3.04 and 3.05 impose general obligations on the Operator to conduct Operations in accordance with good oilfield practice and the Regulations, and Subclause 3.10A is similar. In the absence of the references to Gross Negligence or Wilful Misconduct in those provisions, a Party might have tried to frame a claim for the breach of the overall standards prescribed by Clauses 3.04 and 3.05 and Subclause 3.10A in contract. This could see it only having to prove a breach of contract and its loss without having to prove that the Operator's conduct met the Gross Negligence or Wilful Misconduct test under Clause 4.02. This Paragraph reinforces the Operator's obligation for performance of its other specific contractual obligations under the Agreement with the outcomes noted in the annotations on Clause 4.01.

v) Note the interrelationship between the requirement to carry insurance for the Joint Account under Clause 3.11 and Paragraph (c). Assume that the Operator failed to carry the required insurance and a loss of $1MM occurred which would have been covered by that insurance. In the absence of Paragraph (c) and the modifications introduced in the 2007 document about the Operator's responsibility for breaches of specific contractual obligations, it would not be clear if the Non-Operators had to prove that the failure to carry insurance was due to the Gross Negligence or Wilful Misconduct of the Operator. The inclusion of Paragraph (c) ensures that the Operator is directly responsible for the failure to carry required insurance, and reinforces the importance of compliance to the Operator's personnel.

vi) Note the reference to the deductible in Paragraph (c). Suppose that the Operator failed to carry a required $1MM insurance policy and that a loss of $1 MM occurred which would have been covered thereby. As the policy would have included a deductible, the amount of the deductible would still have been borne for the Joint Account, such that the Operator's responsibility would be $1MM, less the deductible amount.

vii) It is clear in the post-1990 documents that Losses and Liabilities are initially for the Joint Account. The Operator is not required to assume financial responsibility under Paragraph (a), (b) or (c) until its responsibility is confirmed. An allegation that the Paragraph applies is not sufficient. This reflects one of the fundamental principles of the document-that the Operator typically does not bear a disproportionate share of the gains or losses relating to Joint Operations. Any other handling would potentially encourage a Party to make an allegation that the Losses and Liabilities are for the Operator's sole account in order to defer paying amounts owing. Inherent in that other approach is that the Operator would be carrying those costs on the front-end and bearing significant risk if the Non-Operator were financially vulnerable. That could be a major financial burden to an Operator if the exposure were significant or it had modest cash resources. Reinforcing the document outcome is that there are few instances in which an allegation of Gross Negligence or Wilful Misconduct has ultimately been successful.

Clause 4.03: i) Subclause A ensures that Losses and Liabilities are shared if a Non-Operator conducts an activity for the Joint Account. Two examples are the Title Administrator's duties and the application of Clause 10.04 to a proposed Independent Operation in which all Parties participate.

ii) Subclause B provides protection to the Non-Operators if a third party attempts to enforce a Joint Account judgment against any single Non-Operator. As noted in the annotations on Subclause 1.05A, a successful plaintiff can enforce its judgment against any defendant held responsible for the loss unless a Court apportions legal responsibility among defendants.

iii) Clauses 10.16 and 10.18 provide the required protections for Independent Operations.

Clause 4.04: i) This Clause and the definition of Extraordinary Damages are included to limit the potential damages awarded by a Court. Subject to the limit in the definition about a breach of the confidentiality Article, they apply to all damage awards arising out of the Operating Procedure, including those for breach of contract. They include (but are not limited to) the content from the last sentence of Clause 401 of the 1990 document, and are influenced significantly by current international practices.

ii) The exclusion of liability for the loss or delay of production was introduced in the 1990 document, and its inclusion reflected the international practice. Proponents argue that the magnitude of a potential loss of this type is such that it may not be feasible to become the Operator without such an exemption, as the sole assumption of the applicable Losses and Liabilities could potentially threaten the ongoing financial viability of many Operators. This is a particularly relevant consideration when one considers that Operators receive relatively modest overhead recoveries for serving as Operator. The most obvious loss resulting from this type of damage would be a loss of profits.

iii) See Amoco Canada Petroleum Co. v. Propak Systems Ltd., [2004] A.J. 339 (Alta. Q.B.) for a review of the assessment of business interruption damages and deferred production credits when dealing with an agreement that does not have the exclusion in Clause 4.04.

iv) The protection granted by this Clause does not extend to third party damages for which the other Parties are to be indemnified. The provision distinguishes between a Party's damages relating to its own interest and requiring the innocent injured Party to compound its loss by paying cash amounts to a third party for any Extraordinary Damages awarded to the third party by a Court.

Clause 5.01: The Operator is required to maintain its financial records in accordance with the Accounting Procedure. Subject to: (a) the Accounting Procedure; (b) the contracting rights granted under Subclause 3.03B; and (c) the rights granted to the Operator under Article 6.00 for a Non-Taking Party's production, there is a general expectation that the Operator will not gain a profit or suffer a loss because of its role as Operator, other than for any legal responsibility that may accrue only to it because of the breach of its obligations under the Operating Procedure.

The Accounting Procedure provides the Operator with a limited right to use its own equipment or services on a prescribed basis (e.g., Clause 207 of the 1996 PASC Accounting Procedure) or as otherwise approved by the Parties (e.g., Clause 205 of the 1996 PASC Accounting Procedure). In addition, the Accounting Procedure provides the Operator with an overhead recovery that is not related to the Operator's actual overhead cost experience. The marketing of a Non-Taking Party's share of production under Article 6.00 and the associated marketing fee under Clause 6.04 provide an additional potential exception to this general expectation.

Clause 5.02: The Parties are expected to pay Joint Account invoices as and when due. Clause 107 of the 1996 PASC Accounting Procedure requires a Party to pay its bills when due and to challenge any billing issues in due course in a separate process. This becomes less clear in practice if the invoices include incorrect charges for other properties or minimal supporting information to enable a reasonable understanding of the charges.

Subclause 5.03A: i) Clause 5.03 applies to capital advances of costs. It does not apply to operating expenses, which are covered by the Accounting Procedure (e.g., the "operating fund" in Clause 105 of the 1996 PASC Accounting Procedure).

ii) Payment of the advance is linked to the month in which the Operator will be paying its bills, not the month in which the costs were incurred. The Subclause recognizes the fact that costs will generally be incurred prior to the Operator's receipt and payment of the associated invoices. The lag between the time the costs are incurred and when they are paid will often exceed 45 days. The 1990 document clarified that the advance mechanism was linked to the payment of costs, rather than the accrual of the obligation to pay because the work had been done.

iii) Some Operators erroneously believe that this Subclause enables them to require payment of the Non-Operators' full share of costs forecast in the AFE as soon as the AFE is approved.

iv) To illustrate the application of this Subclause, assume that the Operator issues a notice on January 15th requesting an advance for $Z in costs being paid by it in February. A Non-Operator is required to pay its share of the $Z by the later of February 5th (20 days later) or February 15th.

Subclause 5.03B: The adjustment mechanism has historically been substantially the same as that contained in Clause 104 of the 1996 PASC Accounting Procedure. The related billing would be provided to the Non-Operators in the month next following the month to which the advance pertained, as provided in Clause 102 of the 1996 PASC Accounting Procedure.

This Subclause was modified in the 2007 document to allow the Operator to apply an excess advance against the next month's advance. If the original advance request was for $300K when actual costs paid in that month were only $225K, it can either credit the excess $75K against the advance requested by it for the succeeding month or refund the excess. However, the retained excess cannot exceed the next month's advance.

The Non-Operators have access to the default remedies in Clause 5.05 (e.g., interest) if the Operator does not comply with its obligations to provide a refund if its estimate was too high. In practice, these adjustments might not be managed in this manner for small amounts.

Subclause 5.03C: i) This reflects two Operator concerns - security of payment by the Non-Operators and the receipt of adequate funding to conduct the Joint Operation on an ongoing basis. The Operator may require an individual Party to secure payment of its share of the costs of the Joint Operation in a manner satisfactory to the Operator if there is a reasonable basis to believe that the Party would not be able to fund its share of the cost under Subclause A. It might do this by establishing an irrevocable letter of credit in favour of the Operator for its share of costs. On occasion, an Operator may convene a meeting of the Parties to discuss how a well will be financed before issuing the AFE. Amounts obtained by the Operator under this Subclause or Subclause A would be subject to the trust funds mechanism imposed by Clause 5.07.

This Subclause was modified in the 2007 document to provide more process safeguards for Non-Operators because of some abuse of the corresponding provisions under the 1990 document. The exercise of this special discretion is included in the list of items potentially resolved through arbitration under Clause 21.03, such that a Party disputing the request may defer compliance. However, the dispute resolution process will not apply if a Non-Operator is bankrupt, is subject to debtor protection or has a recent history of financial default under the Agreement. The last is of particular importance to Non-Operators with a cash management strategy of deferring payment of receivables an extra 30-60 days beyond their due date.

ii) The normal joint venture billing process prescribed by the Accounting Procedure continues to apply during the period in which a Party is disputing the application of the security for payment process, such that the Operator is never worse off than it would be in the absence of the provision. A Party that does not pay its share of joint venture billings when due remains subject to the potential application of the Clause 5.05 default remedies.

iii) It is important to recall that Clause 9.01 states that approval of a drilling AFE is not the approval of a Completion program.

Clause 5.04: i) This Clause enables a Non-Operator to require the Operator to provide a forecast of anticipated Joint Operations over the succeeding 12-month period. It is seldom used in practice, though. A prudent Operator would discuss the delineation/development of a promising discovery on a technical level anyway in the absence of the Clause, and a Non-Operator would be unlikely to request a forecast for an inactive area. It is an option, though, if an Operator is not advising them of its recommendations for the delineation/development of a significant discovery.

ii) A forecast is for informational purposes, consistent with the practices in J.V. Production Agreements for capital items. They also include a budget process for operating costs, but this is not feasible for most land agreements, even if there are minor Production Facilities.

iii) The first sentence was introduced in the 2015 document. The Parties may wish to include a formal forecast or work program and budget mechanism in the Head Agreement if large capital expenditures are reasonably anticipated with respect to the development of a shale project. It might also be considered as an amendment after a large discovery. It would need to be customized to the particular transaction.

Subclause 5.05A: i) The Operator's lien is included to attempt to secure payment of a Non-Operator's share of costs and expenses by placing a charge on its interest in the Joint Property. It applies to all costs and expenses incurred for the Joint Account, not just those for Joint Operations.

ii) The lien under the 1981 provision probably arose when the expenditure was made, rather than as of the date of the Agreement. Given that a defaulting Party has probably created liens, floating charges or other security in favour of its creditors, the document tries to provide the Operator with the earliest possible claim. Beginning with the 1990 document, this Subclause has been structured so that the Operator's claim arises when the Operating Procedure becomes effective, rather than as the expenditures are made.

The Canada Petroleum Resources Act and comparable legislation resulting from the Newfoundland and Nova Scotia "Accords" expressly provide the Operator with certain advantages in enforcement for frontier properties, in recognition of the fact that lenders should realize that an operating agreement will probably exist under which the Operator would have a lien. This differs from the conventional situation under the *Mines and Minerals Act* (Alberta), for example. It provides only that an Operator's lien may not be the subject of a security notice, such that the actual priority of the Operator's lien will be determined by the legislative and common law rules on priorities. This Subclause is subject to the Regulations. It probably would not be effective against lenders with registered security notices, notwithstanding that they are aware that an Operating Procedure is probably in effect. Similarly, there would be challenges in trying to enforce the remedies in Subclause B against a Non-Operator subject to debtor relief protection.

Subclause 5.05B: i) Default rights are premised on the existence of a default, and are only as good as the validity of the charges under Clause 5.02. An Operator should not resort to these remedies if Parties are disputing an approval, an accounting practice or the adequacy of invoice information.

An Operator that purports to apply the default remedies for amounts that are not owing is in breach of the Agreement. It potentially could be removed as Operator under Subclause 2.02B if its default were to persist, and could also face a claim for damages. A Non-Operator would presumably also seek injunctive relief if the Operator purported to apply any of the harsher remedies in Paragraphs B(e)-(g). An Operator also needs to consider the potential impact on its reputation resulting from legal proceedings or word of mouth if it is using the remedies inappropriately.

It may be attractive to deposit a disputed amount into a trust account until resolution of the dispute, with interest accruing for the successful Party.

ii) As non-defaulting Non-Operators are subrogated to the Operator’s rights under Clause 5.06, this Subclause should not be regarded as a provision for the benefit of the Operator to the detriment of the Non-Operators. It is designed to provide all non-defaulting Parties with appropriate protection if there is a default, while including reasonable safeguards for the protection of the defaulting Non-Operator.

iii) It is important to recall that the purpose of the default remedies is to reinforce payment of owed amounts when due. Operators typically resort to the remedies only when they believe they must. Similarly, Non-Operators must recall that the Accounting Procedure (e.g., Subclause 107(a) of the 1996 PASC Accounting Procedure) contemplates that disputes will be handled through the audit process. A Non-Operator may only withhold payment of a disputed amount under that Subclause with the Operator’s consent.

Paragraph 5.05B(a): Interest should accrue whether or not the Operator has given the Non-Operator prior notice of its intention to charge interest. The inclusion of the “regardless” phrase should eliminate the risk that prior notice is required, as was held in Renaissance Resources Ltd. v. Metalore Resources Ltd., [1984] 4 W.R.R. 430 (Alta. Q.B.), affirmed, [1985] 4 W.W.R. 673 (Alta. C.A.).

Paragraph 5.05B(b): The most obvious use of the suspension of rights is to withhold information from Joint Operations. This is particularly useful as a well approaches target depth. The suspension of other privileges should be considered very carefully in each case, largely because of the potential impact on relationships. (See Duce Oil Ltd. v. Coachlight Resources Ltd., [2000] S.J. No. 352 (Sask. C.A.), affirming [1999] S.J. No. 12 (Sask. Q.B.). The Operator was allowed to install a $100K screw pump and top drive assembly for the joint account without consultation with the defaulting Non-Operator.) The proviso was introduced in the 2007 document, and clarifies the limits in using this remedy. This remedy does not affect the defaulting Non-Operator’s rights and obligations for new expenditures that are proposed or the ability to issue, receive or respond to other notices.

Paragraph 5.05B(c): i) While traditionally not found in agreements, this remedy is basically the codification of a Party's common law rights respecting liquidated amounts. Notwithstanding this general statement, there are common law restrictions on set-off that are beyond the scope of these annotations. If one planned to appropriate funds using set-off as a basis, legal advice should be obtained, particularly under a pre-1990 document. One of the findings in Powermax Energy Inc. v. Argonauts Group Ltd., [2003] A.J. No. 433 (Alta. Q.B.) was that the trust relationship with respect to production revenues prevented an Operator from setting off funds as a self-help remedy “without authority or legal right to do so”.

ii) One question that may arise is whether the seizure of funds accruing to the defaulting Non-Operator under another agreement would place the Operator in default thereunder. As the right of set-off is a common law right and the provision states that the timing of the execution of that other document is irrelevant, this seems unlikely. However, the implications of the exercise of this right should be considered in each case.

Paragraph 5.05B(d): i) While traditionally not found in agreements prior to the 1990 document, this remedy provides the Operator with certain legal procedural advantages because the nature of the claim would be in debt. In essence, it provides a shortcut that may enable the Operator to avoid having to prove that the work was done and the costs incurred, and could allow it to assert simply that the amount is a debt to be collected.

ii) The Bernum case noted in the annotations on the definition of Gross Negligence or Wilful Misconduct also considered the right of set-off in circumstances in which a Non-Operator argued that it was not required to pay amounts owing when it was making a counter-claim against the Operator with respect to an issue that was not yet legally determined. The Court recognized that the Parties are free to contract out of equitable relief, such as set-off. It was unwilling to offer the Non-Operator relief against payment of the amount owing to allow the second issue to be tried after failure of the Non-Operator’s original Gross Negligence or Wilful Misconduct allegation. It was unclear from the judgment if the Court was aware that the last sentence of Clause 4.02 precluded the Non-Operator from withholding any payment of the applicable costs before the original Gross Negligence or Wilful Misconduct claim was judicially determined.

iii) A Paragraph similar to this one was the subject matter of a request for summary judgment in SemCAMS ULC v. Blaze Energy Ltd., 2015 ABQB 218 (Alta. Q.B.) in circumstances in which the applicable agreements also included a provision similar to Subclause 5.05F. The Court determined that Blaze was not able to withhold payment with respect to the invoices while auditing or otherwise disputing the amounts owing. In making its finding, the

Court determined that "…the JIB invoices were prepared in good faith in the ordinary course of business. In other circumstances, for example, if there was evidence of fraud or other misfeasance, the same result may not occur." (This case was under appeal when this document was finalized.)

Paragraph 5.05B(e): i) This provision was introduced in the 2007 document. It enables the Operator to take the defaulting Non-Operator's share of production at the wellhead, to dispose of that production and to apply the proceeds to the debt. The previous provision required the Operator to attempt to obtain sale proceeds from the purchaser of the defaulting Non-Operator's share of production, although the Court in Powermax determined that the previous version allowed the Operator to seize production if it satisfied the other requirements of the Clause (e.g., there is a default).

This presented two challenges. The Operator could not require the third party purchaser of production to cooperate. In practice, the best that could probably be hoped for would be payment of those proceeds into a trust account or into Court. This could greatly limit the potential application of that remedy in practice. The shift from "dedicated lands" to "corporate warranty" sales contracts also typically makes it very difficult to identify the purchaser of the product. (A defaulting Party with a dedicated lands contract would be very motivated to cure any default if this remedy were used.)

ii) In practice, the Operator would usually manage the volumes in the same manner as its own production. This would place the defaulting Party in breach under its sale contract, where this would be particularly problematic for a dedicated lands contract. This presents a very strong incentive to remedy the default, and the primary and secondary notice mechanisms provide ample opportunity to do this.

iii) Production is to be disposed of for a Market Price. This is basically a price that is not unreasonable in the circumstances.

iv) An Operator considering use of this remedy would need to have access to infrastructure to manage the incremental volumes.

Paragraph 5.05B(f): i) This remedy was introduced in the 2007 document. The Operator (but not the defaulting Non-Operator) has the option to reverse a participation decision of a defaulting Non-Operator and subject it to the consequences of non-participation prescribed by Article 10.00 for the unpaid and remaining costs of the applicable Operation. The remedy attempts to balance the needs of the defaulting Non-Operator and the other Parties. It is premised on the defaulting Non-Operator not paying amounts payable by it under Clause 5.02. The Operator must give specific notice of its intention to use this remedy, and is to identify in that notice the amount owing and any application of the reimbursement requirement relating to a forfeiture, as noted in annotation (ii).

The defaulting Non-Operator may avoid this outcome by paying the amounts owed by it within five Business Days after receipt of that notice. During that period, the other non-defaulting Non-Operators may assume a proportionate share of the costs of the defaulting Non-Operator in the applicable Joint Operation by making a participation election on the same basis as in Subclause 10.02C, where failure to respond is deemed an election not to assume any portion of the defaulting Non-Operator's share of costs. To ensure that 100% of those costs are assumed, the Operator is deemed to elect to assume its proportionate share of all available interest.

The Parties need to be aware that the other remedies for that default in Subclause 5.05B are no longer available to them if they choose to use this remedy, as the defaulting Non-Operator's status has been changed to that of a Non-Participating Party for its unpaid share of costs of the Operation. The net effect of this construction is that an Operator is likely only to use this remedy in practice if the information it has in hand has not downgraded the potential of the well.

ii) Suppose that the defaulting Non-Operator paid $300K, but didn't pay the last $200K of its share of costs. If the Joint Operation was the drilling of an Exploratory Well to which a 500% cost recovery applied under Subclause 10.07A, the 500% cost recovery would apply to the costs not paid by it. On the other hand, the Parties would need to reimburse the defaulting Party the $300K already paid by it in order to apply a Clause 10.10 forfeiture initially identified in the Operation Notice. The potential reimbursement obligation would influence use of the remedy and the Parties' elections.

iii) Parties using this remedy need to ensure that the outcomes are clear when setting up their records to reflect any cost recovery created under this Paragraph and in all associated communications with other affected internal groups, such as accounting. This is particularly so if the defaulting Party had paid a portion of its share of the costs of the Operation.

Paragraph 5.05B(g): i) The seizure and sale remedy in this Paragraph is an exceptional remedy that would only actually be used in extreme cases.

ii) A defaulting Non-Operator's interest would often be pledged as security to lenders, such that the price to be paid by potential purchasers would probably be heavily discounted if a sale under those circumstances were even feasible. A sale would be further complicated if the defaulting Non-Operator's interest were subject to a dedicated lands gas sales contract.

It is probably advantageous to obtain approval of the other non-defaulting Parties for use of this provision because of the possibility that there may be litigation associated with the exercise of this exceptional remedy.

Because of the special circumstances in which this remedy would be likely to be used, potential issues associated with effecting a forfeiture of lands, the potential impact on third parties, the potential difficulty in effecting assignments, potential valuation issues and the possible reluctance of purchasers to acquire the interest without a Court order, any sale under the post-1990 documents is subject to any required Court order. This outcome is consistent with the Court's determination in Novalta Resources Ltd. v. Ortynsky Exploration Ltd., [1994] A.J. No. 1101 (Alta. Q.B.) that Part 37 of the Alberta Rules of Court would apply to the use of a seizure and sale remedy like that contemplated in this Paragraph.

That case could potentially also limit the ability of an Operator to use the seizure and sale remedy in pre-2007 versions of the document.

iii) Note the duty on the Operator to attempt to sell the seized property on reasonable terms, having due regard to the potential for the recovery of excess funds for the defaulting Non-Operator. Otherwise, the Operator has no incentive in the contract to attempt to sell the property for greater than the amount owed to it by the defaulting Non-Operator.

iv) A sale is without prejudice to the Operator's claim for any amount still owing after the sale.

v) One of the potential challenges in effecting this remedy is the execution of the associated transfer documentation. Notwithstanding the "Further Assurances" Clause (25.01), there is a real possibility that a defaulting Non-Operator would refuse to execute that documentation. To address this issue, the Operator is authorized under the post-1990 documents to execute those documents as the defaulting Non-Operator's attorney if the defaulting Non-Operator fails to execute those documents promptly following delivery to it. The Court order step validates this outcome to third parties.

Subclause 5.05B-Ending: i) There are differences in access to the remedies of interest, the withholding of information and the seizure remedy. The interest remedy (Paragraph (a)) applies by its own terms without any requirement to issue a default notice, and the remedy in Paragraph (b) applies immediately after service of that notice. The harsher seizure remedy (B(g)) is only available if the default has continued for at least 60 days after service of that notice, an increase from the 30-day period in the pre-2007 documents. The 60-day period provides access to this exceptional remedy before the default imposes a serious hardship on the Operator, while decreasing the likelihood that a Court would use its discretion to prohibit use of the remedy. The traditional 30-day period after notice applies to the remedies in Paragraphs B(c)-(f), where Powermax reinforced the need for an Operator to follow the required process. Several of the Paragraphs ((e), (f) and (g)) require notice of the specific intention to apply the remedy. That additional notice may be served before expiry of the initial notice, but the remedy cannot be effected before expiry of the first notice period.

Subclause 5.03C of the post-1990 documents enables an Operator to require a Party that received a *bona fide* default notice within the preceding six months to post security under the capital advance process. This will impact Parties that regularly pay invoices on a delayed cycle, and encourage more timely payment.

ii) The increase in the waiting period for the seizure and sale remedy to 60 days after issuance of the default notice is likely to see default notices issued more often than has been the case. Increased vigilance in this area helps increase the visibility of the default and the potential implications associated with imposition of the default remedies. This increases the likelihood that the Parties will address the default sooner.

Subclause 5.05C: This Subclause was introduced in the 2007 document. It enables a defaulting Party to obtain a statement of account that shows the amount owing by it and the credits and debits processed against its account. Its most likely use would be in the circumstance in which the Operator was withholding the defaulting Party's share of production under Paragraph 5.05B(e).

Subclause 5.05E: This provision is included because of the *Judgment Interest Act* (Alberta). It operates to merge a judgment of principal and interest, and limits post-judgment interest to the rate set by regulation each year. While the *Interest Act* (Canada) allows for post-judgment interest at a contractual rate, that Act has no application to any judgment in Alberta as of August 1, 1992 because of amendments to that Act. (See National Trust Co. v. Conroy, [1995] 6 W.W.R. 363 (Alta. Q.B.) and AVCO Financial Services Canada Ltd. v. Kilbreath (1996), 45 Alta. L.R. (3rd) 218 (Alta. Q.B.).) Notwithstanding this provision and Clause 25.05, this Subclause will not be effective in the absence of an amendment to the legislation.

Subclause 5.05F: Subject to audit rights, the Operator's *bona fide* records constitute *prima facie* proof of a financial default. Without this Subclause, it would have greater difficulty presenting evidence about the amount owing. (See the annotation on Subclause 3.01C respecting Renaissance.)

Subclause 5.05G: If the Operator is the defaulting Party, the Non-Operators assuming the Operator's share of costs may appoint a Party to act as their representative to exercise the default remedies otherwise available to the Operator, pending the appointment of a new Operator.

Subclause 5.05H: This protects a Party that pays another Party's unpaid share of lessor royalties to preserve any of the Title Documents.

Clause 5.06: i) The Operator may use this Clause after a Party has been in default for 60 days if the Operator has not applied the non-participation remedy in Paragraph 5.05B(f). The Non-Operators are required to reimburse the Operator its out of pocket costs associated with the default.

This reflects the policy objective that the Operator is not to suffer a loss relative to the Non-Operators as a result of being the Operator. In the absence of this Clause, the Operator would ultimately bear the entire risk for financial default by a Non-Operator.

ii) The contributing Non-Operators are not required to reimburse the Operator interest which has accrued on the unpaid principal at the time the Operator uses the mechanism.

iii) The time for this request was reduced from three months to 60 days in the 2007 document to encourage dialogue by the Operator and the other non-defaulting Parties about the potential use of the default remedies.

iv) This provision would extend to losses incurred for the Joint Account under Article 4.00, since those losses would pertain to Joint Operations. If the Parties were held liable to a third party for a loss it suffered as a result of a Joint Operation, the Parties would be jointly responsible for the loss unless the Court had apportioned responsibility among the defendants in its judgment. It would be an odd result if the Operator were required to contribute the share of an insolvent Party without a corresponding right to have the remaining Parties share that burden.

Clause 5.07: i) There had been some suggestion in the late 1980s that Operators should be required to hold funds in distinct trust accounts because of the view that creditors could otherwise seize Joint Account funds in the event of an Operator's insolvency.

However, the Alberta Court of Appeal decided in Bank of Nova Scotia v. Societe General (Canada) et al., [1988] 4 W.W.R. 232 (Alta. C.A.) (sometimes referred to as the Sorrel decision) that a trust relationship is imposed under the conventional commingling clause of the 1981 document, as the intention that the Operator acts for the benefit of the Non-Operators pervaded the entire document. The provision was expanded in the 1990 CAPL Operating Procedure to reflect that decision. (See also Sturrock v. Ancona Petroleums Ltd. (1990), 75 Alta. L.R. 216 (Alta.Q.B.).)

The Sorrel case, though, addressed a fact situation in which the lender was not the same institution as that with which the funds were deposited. Usually, funds would be on deposit with the lender, such that the typical lender may have rights of set-off which may prevail over the claims of the Non-Operators unless the lender knew or ought to have known that the funds were held in trust for the Parties.

Prudent Non-Operators should continue to monitor their properties for indications that an Operator may have serious financial difficulties. It may be attractive to consider replacing such an Operator under Clause 2.02 or 2.03. It may also be desirable to use the leverage under those provisions to require an Operator to set up a separate trust account or to hold Joint Account monies at a bank to which the Operator is not indebted.

Brookfield Bridge Lending Fund Inc. v. Karl Oil and Gas Ltd., [2009] A.J. No. 509 (Alta. C.A.), reversing [2008] A.J. No. 1085 (Alta. Q.B.), illustrates the risks to Non-Operators in this regard. The issue in that case was whether the trust created by Clause 507 of the 1990 document gave the Non-Operators priority to funds in the Operator's bank account relative to a secured creditor. In that case, the Operator had removed trust funds from the commingled funds in its account for unauthorized purposes. Had the trust funds remained in the Operator's bank account, the Court confirmed that those funds would have been regarded as being held in trust for the Non-Operators in priority to the Operator's secured creditor.

Faced with deciding which of two innocent parties would be adversely impacted, the Court of Appeal found in this particular instance that the trust obligation applied only to the lowest positive balance in the Operator's bank account at the relevant time. The Court also noted that the Non-Operators created the risk of misappropriation of funds by allowing commingling.

This decision creates vulnerability any time that a distressed Operator diverts trust funds for other purposes in a way in which the account balance was less than the amount that should have been held as trust funds. Non-Operators can mitigate their risk in this area by being vigilant in watching for warning signs of an Operator's insolvency, by taking in kind, by not allowing an Operator to hold production proceeds for any material period of time in contravention of Clause 6.06 and by refusing to advance 100% of their share of approved Operations under Subclause 5.03C (versus the one-month capital advance contemplated under Subclause 5.03A).

ii) The nature of the traditional right to commingle may be unclear after Sorrel 1985 Limited Partnership v. Sorrel Resources Ltd., [2000] A.J. No. 1140 (Alta. C.A.), reversing [1997] A.J. No. 225 (Alta. Q.B.). It pertained to a general manager of a partnership that obtained advances from the partners well in advance of the cash outlays required for partnership activities, in breach of the agreement. It then used the funds to pay its own costs and internal expenses, when the Court found on the facts that it knew it was vulnerable to creditors. While the Trial Judge determined that it breached its trust obligation to the partners in its handling of those funds, the Court determined that commingling was an accepted practice in the industry for parties in a relationship under an agreement. The Court of Appeal determined, however, that there was not sufficient evidence to find that this was an accepted practice, where there was specific evidence to the contrary for general partnerships. It also determined "...It is not acceptable for a trustee to use trust funds for its own purposes, even in the expectation that it will be able to repay those funds."

The Court of Appeal imposed liability personally on two of the officers of the general partner because they knew that the general partner did not have funds to cover its own operational expenses at the time they chose to appropriate the funds provided by the other partners. (See also Air Canada v. M&L Travel Ltd. (1993), 108 D.L.R. (4th) 592 (S.C.C.), affirming (1991), 77 D.L.R. (4th) 536 (Ont. C.A.) with respect to the potential imposition of personal liability on the principals of a corporation.)

iii) As noted in the annotations on Subclause 2.02A, Non-Operators have sometimes been prevented from removing an Operator in financial distress under the corresponding provisions in pre-2007 versions of the document. Although the relevant provisions of the 2007 document were modified to increase the likelihood that the Parties could remove an Operator meeting any of the tests in Paragraphs 2.02A(a)-(d), there is no guarantee that the modifications will be successful. This Clause was modified in the 2007 document, so that the right to commingle funds terminates (and the obligation to segregate funds held hereunder accrues) if the Parties are precluded from removing an Operator under Subclause 2.02A.

iv) One of the major difficulties with the mandatory creation of individual trust accounts would be the imposition of significant incremental administration on all Operators, instead of only problem Operators. Another major difficulty would be in monitoring compliance of the obligations. The inclusion of the obligation would not mean that there would be compliance, particularly if an Operator were in financial distress.

v) Re Blue Range Resources Corp., [1999] A.J. No. 929 (Alta. Q.B.) addressed when funds are "received" in a commingling situation. It pertained to a processing arrangement in which Blue Range was an owner and contract operator. The Court determined on the facts that journal entries on Blue Range's books to show an obligation to pay at the required time did not mean that the contemplated amounts had been "received".

Subclause 6.01A: i) Each Party is required to take its production in kind at the First Point of Measurement in the post-1990 versions of the document. The 1974 document required the Parties to take in kind, and the 1981 and 1990 documents provided the Parties with the right to take in kind. There is little substantive difference between the two approaches in the post-1990 documents, as a Non-Taking Party is subject only to the consequences prescribed in Article 6.00 for a failure to take in kind (i.e., the Clause 6.04 marketing fee, but not a remedy in damages for breach of contract or any other purported charge or Operator imposed "inconvenience fee"). The Parties remain free to negotiate a different consequence in their Agreement.

ii) There will be situations in which an Operator would prefer to manage additional volumes under asset specific marketing arrangements.

iii) Each Party remains responsible for costs and expenses applicable to substances produced in association with P&NG, such as associated water.

iv) The 2007 document clarified that the risk of loss prior to the delivery point was for the Joint Account, subject to the Article 4.00 exceptions.

v) A Party is required to provide the Operator with such information about its marketing arrangements as the Operator reasonably requires to fulfil its obligations to transfer possession of production.

Subclause 6.01B: The Operator has limited authority to contract gathering, processing or transportation service for the Joint Account without the Parties' approval. The Parties may wish to discuss this when considering the development of a significant gas prospect. However, a Party disposing of a Non-Taking Party's production under this Article, may, for that Non-Taking Party's account, contract for such incremental services as are reasonably required to market those volumes. In practice, the disposing Party would typically not contract for transportation beyond the first liquid sales point.

Subclause 6.02A: i) Notwithstanding the document provisions, the Parties would be highly motivated to attempt to negotiate an appropriate asset specific marketing arrangement in practice if the volumes are significant and a Non-Taking Party is unlikely to take in kind in the near term.

ii) The Operator may dispose of a Non-Taking Party's production under short term arrangements that do not exceed 31 days, unless the applicable contract can be terminated on less than 31 days' notice. Without that right or the negotiation of a separate production balancing arrangement (as addressed in the AAPL Operating Procedure), the well would have to be shut-in.

The provision in the 1981 document stated that production marketed on behalf of another Party was to be sold "at the same price which the Operator receives for its own share of the production" or purchased "for its own account at the field price prevailing in the area." That provision seemed satisfactory in the 1970s and the early 1980s, when markets were readily available for gas and prices were regulated. Problems were apparent, though, when there was a surplus of available gas and a large variation in gas prices after deregulation. A Non-Operator without a long-term contract that took in kind was then usually forced to sell into a heavily discounted spot market. An Operator with a long-term contract faced the risk that a Non-Operator without such a contract would prefer the Operator market its production, rather than sell into an unfavourable spot market. Assuming that the Operator was meeting its deliverability requirements, this arguably could require the Operator to displace its own production to sell a Non-Operator's production under its contract. In the alternative, the Operator could purchase the Non-Operator's production at "the field price prevailing in the area," when the meaning was unclear when prices for similar production varied drastically.

The meaning of that phrase in the 1981 document was considered in Erehwon Exploration Ltd. v. Northstar Energy Corp., [1994] A.J. No. 916 (Alta. Q.B.), in which the Court determined that it meant "spot price".

The Clause attempts to balance the needs of the Operator and Non-Operators. The Operator requires protection that it is not required to displace its production to accommodate a Non-Operator. It also wants to be compensated for any extra expenses it incurs by marketing another Party's share of production. A Non-Operator must be protected from unreasonable long-term contracts or non-arm's length arrangements.

The Subclause has been structured so that the Operator may: (i) sell that production under another arm's length transaction at a Market Price (as defined in Clause 1.01); or (ii) buy the production for a Market Price. The 1990 document also enabled the Operator to sell the production for the same price as it receives under the sales contract under which it sells its own production. This was not retained in the 2007 document because of the shift to corporate warranty gas sales arrangements and restrictions on the sale of non-equity volumes under reserves based dedicated land contracts.

iii) The post-1990 documents link the charges for product enhancement costs to the Facility Fees definition. This provides protection for both the disposing Party and the Non-Taking Party. It provides greater clarity that the disposing Party manages the incremental volumes as if they are third party volumes at its facilities, while including some controls on the fees that can be charged.

iv) The marketing fee applies to all dispositions of the Non-Taking Party's volumes under the post-1990 documents. The 1990 document did not apply the marketing fee to non-arm's length transactions.

v) One issue that may arise is the possibility that the Operator may sell production at a higher price than the Market Price. However, it would be difficult for an Operator to argue that the proposed Market Price was, in fact, the Market Price if the production could easily be sold on the spot market at a significantly higher price. The most probable resale case, then, would be the situation in which the Operator has excess capacity under an attractive long-term contract that it is not willing to share. Because of the greater possibility that the determination of Market Price could be challenged in this situation, a prudent disposing Party would document its determination of Market Price in reasonable detail in this circumstance.

The Court also considered the resale scenario in Erehwon, and concluded that there was no prohibition on resale for profit under the 1981 document. The Court's view was a limitation such as "and for its own use" would have been included if that had been the intention.

Subclause 6.02B: i) Purchases may not exceed 31 days, unless the applicable contract entered into by the Operator is terminable at any time on notice of not greater than 31 days. If the Operator proposes to sell production under contracts that either exceed 31 days or are not terminable at any time on notice of not greater than 31 days: (a) the Operator is required to notify the Non-Taking Party of that intention, together with a summary of the material terms; (b) the Non-Taking Party will elect, within five Business Days after its receipt of that notice (or such longer period as the Operator may specify therein), if it wishes its production sold under that contract, where failure to respond is deemed to be a refusal to consent to the sale; and (c) if it does not consent to the contract, it must advise the Operator if it intends to take in kind or if it wishes the Operator to continue to market the production under the short term arrangements in Subclause 6.02A.

ii) Note the five-Business Day response period in Paragraph B(b). Attractive short-term contracts are probably only available for a limited period of time. A longer election period could result in the loss of a contract. The Operator may designate a longer response period if it has additional flexibility. The deeming mechanism in the 1990 document was a deemed consent. It has been reversed because of the logistical difficulties in making the assessment on a short time frame. The change also reinforces to the Operator the benefits of giving a longer election period when feasible.

iii) The Non-Taking Party can continue to require the Operator to sell its production under short term arrangements if it is not prepared to consent to a contract. It may be unwilling to consent if it believes that it can obtain a better contract in the next few months, for example.

iv) The 31-day restriction may pose problems in the disposition of LPGs. There would likely be some difficulty selling the product on the spot market, and LPG contracts generally have a one year - evergreen term, with a window to cancel at the end of a year upon 60 days' notice. LPG contracts also usually relate to supply sources, such as gas plants, rather than individual wells. Given the limited spot market for LPGs and the nature of LPG contracts, it is likely that a Party that does not intend to take its share of LPGs in kind for a sustained period would in practice negotiate a suitable arrangement with the Operator in the context of the particular fact situation.

Subclause 6.02C: A Non-Taking Party may subsequently wish to take its production in kind. The election will generally be effective at the end of a contract permitted under Clause 6.02. If the contract is terminable, the election will be effective at the date the agreement is terminated, provided the Operator has received the election at least 15 Business Days before any specific date upon which it may terminate the arrangement. Sales arrangements are typically handled on a production month basis, so the Clause includes a proviso that any election to take in kind is effective on the first day of the calendar month next following expiration of the applicable period. However, there may be circumstances in which a temporary failure to take in kind may see the Operator and the Non-Taking Party agree to a different handling in their particular circumstance.

Clause 6.03: i) This Clause addresses the possibilities that the Operator may be the Non-Taking Party and that it may be willing to take only its own share of production in kind if there is a Non-Taking Party. (Clause 6.02 provides the Operator with the right, but not the obligation, to market a Non-Taking Party's share of production.) The Operator must provide the other Parties with the information they require to exercise their rights under the Clause. These rights will be shared by the Parties in proportion to their Working Interests, unless otherwise agreed by them.

ii) Suppose X (Operator) and Y have not been taking in kind and that Z has been selling their share of production under Clauses 6.02 and 6.03. X now begins to take in kind. Who will market Y's production once the Operator begins to take its own production in kind? If Y's share of production is being sold under a Clause 6.02 contract, Z would manage the production until termination of that contract. At that point, and assuming Y did not then begin to take in kind, the Operator could sell it under Clause 6.02. Z would only have the right to sell it under Clause 6.03 insofar as X did not.

Clause 6.04: i) A disposing Party may charge the Non-Taking Party a marketing fee for production being managed by it, including in the post-1990 documents (but not the 1990 document) volumes being purchased by the disposing Party. If the Parties prefer to market collectively through the Operator because of its access to gas markets, they are free to tailor an arrangement to their situation and waive the fee for those dispositions.

ii) The marketing fee is not based on the ultimate sale price, but on the “value” of the product at the wellhead or the “value” of gas and associated products at the plant gate, as applicable. Although easier to calculate than a wellhead based fee, a fee based on the gross sale price could be significantly greater, depending on the ultimate point of sale and the degree to which the product had been enhanced.

The reference “calculated at the wellhead” in the Clause does not refer to the substances calculated at the wellhead. The substances cannot be calculated until the First Point of Measurement, which will often be after processing raw gas. Instead, the provision refers to the value of the substance at the wellhead. This is determined by subtracting from the applicable Market Price all of the costs and expenses associated with product enhancement, such as transportation, insofar as it has not already been taken into account in the determination of the Market Price.

iii) The percentages are lower than were used in the 1990 document to reflect forecast pricing models, but some minimums have been included. Parties will sometimes choose to override these percentages with a higher percentage to reinforce the expectation that the Parties are to take in kind (i.e., foothills environment) or to encourage the Non-Operator to enter into an asset specific marketing arrangement with the Operator. As noted in the first annotation on Subclause 6.02A, the Parties should consider an asset specific marketing arrangement if the volumes are significant and the Non-Taking Party believes that it is unlikely to take in kind in the near term.

iv) The 1990 document included an Alternate B that enabled the Parties to tailor the fee ($ or %) to individual products in their particular fact situation. It was removed from the 2007 document because it was used very infrequently. However, minimums have been included for gas and sulphur.

v) The marketing fee was chosen in lieu of charging the actual cost of marketing. The fixed percentage fee was attractive because of its simplicity and certainty. Given the subjectivity inherent in the allocation of overhead, it would be very difficult to quantify and audit actual marketing costs.

vi) The terms petroleum, natural gas, etc., have not been defined. Both the terminology and the definitions vary between jurisdictions.

Clause 6.05: i) A Party marketing a Non-Taking Party's share of production under this Article may, by notice to it, pay the associated royalties directly to the lessor. This is an exceptional right. The incremental administration associated with the process is such that an Operator would probably only ever consider doing this if it believed that the Title Document would otherwise be at risk (i.e., concerns about Non-Taking Party’s viability). The Non-Taking Party is to provide such information as may reasonably be required to make that payment, such as company specific information respecting gas cost allowance (introduced in the 2007 document). Those royalties would then be deducted from the amount payable under Clause 6.06.

ii) The Operator is required to provide production statements to the Parties under Clause 3.12 to assist them with the calculation of their royalties.

iii) Subclause B was introduced in the 2007 document. It is an indemnification from the Non-Taking Party for payments by a disposing Party on its behalf. The indemnification is contingent on the amounts paid being consistent with the information provided by the Non-Taking Party and the distribution of proceeds under Clause 6.06 being consistent with the payments made under this Clause.

iv) Clause 3.13 of the 2007 document was modified to recognize that an Operator that is the lessee under the applicable freehold lease will often pay any applicable freehold mineral tax and invoice the applicable Working Interest owners for their respective shares.

Clause 6.06: i) Funds held by the disposing party on behalf of a Non-Taking Party are held in trust under Clause 5.07. The disposing Party must pay the Non-Taking Party its share of net proceeds not later than the 25th day of the second month after the production month. Clause 5.05 applies, *mutatis mutandis*, to a failure to pay, such that the Non-Taking Party would have access to interest and the other default remedies.

The corresponding Clause in the 1981 and 1990 documents required production proceeds to be distributed within 10 days after their receipt. While some Parties will apply the historic “cheque exchange day” philosophy in managing production proceeds, the practice has been honoured more frequently by its breach. The modified requirement in the post-1990 documents better reflects the timing constraints of the accounting cycle for the majority of industry. However, nothing prevents Parties from managing this process on a shorter cycle. A Non-Taking Party would be particularly motivated to request this if the proceeds were significant, especially if there were a well-established relationship with the disposing Party.

ii) The Clause has been structured so that the disposing Party assumes the risk if the purchaser of a Non-Taking Party’s production being marketed by it fails to pay unless the volumes have specifically been sold under a particular contract. The main reason for this approach is that corporate warranty sales contracts would otherwise often enable a Party to allocate a Non-Taking Party’s volumes managed by it to its problem contracts.

iii) The direct processing and transportation costs may not be known at the time of the distribution of proceeds. The disposing Party may invoice the Non-Taking Party for those costs after the fact. In such event, the disposing Party also has access to the default remedies in Clause 5.05 to secure payment of those expenses. As a Non-Taking Party could still receive proceeds in the situation in which a purchaser of its production does not pay, it remains responsible for its share of the costs described in Subclause 6.06B.

iv) The post-1990 documents include additional flexibility, to recognize that the calculation may need to be based on estimated production volumes, particularly if the distribution is made on a shorter cycle. The disposing Party would identify that the calculation was made on the basis of estimated production data in its statement. Any financial adjustment would be made in the next month, with the adjustment identified on that statement.

v) Production rates fluctuate daily, so accounts will be adjusted once per month.

Clause 6.07: A Non-Taking Party has the right to audit the disposing Party's records for production volumes and costs associated with Petroleum Substances sold on its behalf under Article 6.00. However, the disposing Party is not required to provide those auditors with any access to any contract under which the disposing Party sells its own Working Interest share of production, except insofar as the audit is conducted by the external auditors of the Non-Taking Party under reasonable conditions of confidentiality. Those contracts contain proprietary information that a Party is not required to disclose to the Non-Taking Party's internal auditors.

Clause 6.08: A Party selling production is often required to provide a title warranty for production being sold by it. As it is not feasible for a disposing Party and a Non-Taking Party to enter into a side agreement in each instance, this general indemnification provision has been included.

Paragraph 7.01(a): i) A Non-Operator will occasionally object to the Operator's AFE and insist that it can conduct the Operation at a lower cost. In some cases, it may be attractive to negotiate a turn-key arrangement whereby that Non-Operator conducts the Operation. However, it is not feasible to include such a provision in the document because of the degree to which the decision to negotiate such a mechanism would depend on such factors as the timing of the Operation and the perception of the Non-Operator's financial viability and technical expertise.

ii) An AFE will be void unless it is approved by all Parties within 30 days after its submission to them, provided that the Operator has the option to extend this period to 75 days as of the 2015 document with respect to repair or maintenance of the Joint Property. The proviso was included because of industry's experience that AFEs for repair and maintenance type activities are frequently not handled in an expeditious manner by Non-Operators. The notice mechanism provides the Operator with this right to mitigate the need to re-issue the AFE if one or more of the Parties are tardy with their approval.

The inclusion of a time limitation ensures that a Party is not bound by an AFE approved by it for a prolonged period while waiting for responses.

iii) It is preferable to send well AFEs through an Operation Notice under Article 10.00. This creates a consequence for failure to approve it, and secures the Operator's role in conducting the work if Alternate 10.04A(a) applies.

iv) The Operator is to advise the Parties about the status of the AFE as soon as the position of the Parties is clear.

Paragraph 7.01(b): i) Assuming that all Parties approve the AFE, a sunset provision is required to ensure that they are not bound indefinitely by the AFE. This Subclause mirrors the period for Commencement of an Independent Operation under Clause 10.03, and is subject to the potential application of the Force Majeure Article (Article 16.00). The Parties should consider increasing this period if it is not appropriate for their project area.

ii) Operators will conduct their wellbore abandonment and the subsequent reclamation and remediation programs relating to the Abandonment in phases that will each have an AFE. They will also schedule their applicable work program at a time that reflects the most efficient way for them to manage the organizational AR&R schedule in the context of the allocation of personnel and equipment and any resultant cost efficiencies.

Operators conducting AR&R programs should also advise the other Parties of any material developments about the program in a timely manner once they are discovered (i.e., a very complex, expensive reclamation relative to what had originally been expected).

Paragraph 7.01(c): A separate Operation Notice will sometimes be served for an Operation after issuance of an AFE that is not served as part of an Operation Notice under Article 10.00. If all Parties approve the original AFE within the response period for the Operation Notice, the Operation Notice is void. However, the Operation will be conducted under the Operation Notice if the original AFE is not approved and all Parties approve the Operation under the election process for the Operation Notice in Clause 10.02. This is because: (a) the Operation described in the Operation Notice may be somewhat different from that to which the AFE pertains; (b) the timing of issuance is later; and (c) of the possibility that a Non-Operator may have issued the Operation Notice in circumstances in which it would be the Operator for the Operation under Clause 10.04.

Paragraph 7.01(d)(ii): The Operator's proposed program should be provided to the Non-Operators at the earliest opportunity. This provides the Parties with an adequate opportunity to resolve any differences they may have about the program. It would be preferable to require an Operator to forward the proposed program with the AFE (or at least a week before Commencement). However, industry experience indicates that Operators would be unlikely to comply with the obligation unless specifically requested to do so by the Non-Operators.

Notwithstanding the fact that the program is generally provided to the Non-Operators close to the time the well is Spudded, most objections would tend to be about the proposed logging and coring program, such that there is usually an adequate opportunity to resolve any differences without disruption to the Operation. While these objections tend to be resolved fairly easily in practice, there is admittedly a problem if the Parties are unable to negotiate an acceptable arrangement after Commencement of the well.

There may be circumstances in which the drilling program may address major issues that are fundamental to the Operation (e.g., horizontal drilling, special treatment of formations). In those circumstances, it is the better practice to discuss those issues before approval of the AFE.

This treatment of the proposed program differs significantly from that prescribed by Clause 9.02 for the Completion program because of the increased probability that there could be differences of opinion on major components of the Completion program.

Clause 7.02: The Operator will also be required to provide well information to regulatory authorities under the Regulations and possibly to a lessor under a particular Title Documents (e.g., Prairie Sky/Encana/PanCanadian form lease). This obligation is captured under the general obligations in Clause 3.04, which includes the requirement for the Operator to comply with the Regulations and the Title Documents.

Clause 7.03: The Parties will have different expectations for wells drilled as core holes or as injection or disposal wells.

Paragraph 7.03(a): This Paragraph has traditionally stated that each Non-Operator will have a reasonable opportunity to observe the conduct of the logging program. This requirement was eliminated in the 2007 document because advances in technology enable the Non-Operators to receive logging information on a real time basis at their offices.

Clause 7.04: The Completion approval is obtained under the Casing Point election process in Article 9.00 or the response to an Operation Notice issued under Clause 10.02 (re-entry and Completion under Clause 10.08).

Clause 7.06: i) The Operator is to supply data in accordance with established industry standards. The Operator might require reimbursement of incremental costs to accommodate a Non-Operator's request for data in an unusual format.

ii) There have been circumstances in which Operators have refused to provide the Non-Operators with data that was obtained at the expense of the Joint Account and others in which Operators have used their position as Operator to conduct testing programs in the Joint Lands for their own account without having provided the Parties participating in the well the opportunity to participate in the acquisition of that data. The revisions to this Clause reiterate the Operator's obligation to distribute data that was acquired at the expense of the Joint Account and remind Operators of the existing duty under Clause 7.07 to provide the other Parties participating in the well with the opportunity to participate in any evaluation of the Joint Lands that the Operator proposes to conduct. This reflects the foundation principle expressed in Clause 5.01 that "…It is the Parties' general intention that the Operator not gain a profit or suffer a loss because it is the Operator…".

Clause 7.07: i) This is an enabling provision. A Party may conduct testing programs in a well in addition to those tests conducted under Article 9.00 (e.g., additional tests in a formation that has already been evaluated under Article 9.00) at its sole cost, risk and expense, provided hole conditions are, in the Operator's reasonable opinion, satisfactory. The liability and indemnification provisions of Clause 10.18 apply to this program.

ii) The consequences in Article 9.00 apply to any testing program conducted under that Article.

iii) The provision does not entitle a Party to use a joint well to evaluate formations that are not included in the Joint Lands. A Party that wishes to conduct such a test would need to obtain the consent of the other owners to that use of the well. Otherwise, this use of the joint well would see it using the Joint Property to subsidize its other operations. Similarly, it does not enable a Party to use a wellbore not subject to this Agreement to test formations in the Joint Lands, since this could prejudice the other Parties. (See also Clause 10.06 and the associated annotations.)

Article 8.00 (General): i) The 2007 version of this Article was designed to address only relatively straightforward situations involving Horizontal Wells. The 2015 document was modified to add breadth and depth to the coverage of Horizontal Wells throughout the document by including a number of changes to reflect the increasing use of "long reach" Horizontal Wells (i.e., Subclauses 3.01D, 3.01E and 10.02H) and the likelihood that the Parties will negotiate transaction specific provisions to address such matters as Multiple Well Drilling Programs and the development of Well Pads.

The Article has been structured so that the special provisions for Horizontal Wells are largely contained in this Article. If more complex Operations beyond the scope of this Article are expected or contemplated, such as secondary or tertiary recovery schemes, the Parties should amend the Operating Procedure or the Head Agreement to address their particular circumstances.

If the applicable well is proposed through an Operation Notice, this Article operates to supplement the Article 10.00 process by addressing issues associated with proper identification of the activity and the procedural platform for the relationship between the applicable participants.

ii) The benefits of presenting these provisions in a self-contained module would be more apparent if they were instead integrated throughout the document. The added references throughout the document would be suboptimal to users who were not familiar with horizontal drilling, since they would not be presented with a snapshot of the issues in one location.

Clause 8.01: i) Horizontal Wells are by their nature subject to much more variation from the original drilling plans than are vertical wells. Operators of Horizontal Wells will typically respond to conditions encountered in a given formation by varying the length and direction of the proposed Horizontal Legs. At the same time, there must always be some reasonable restrictions on the flexibility and discretion afforded to the Operator of a Horizontal Well by the participants in the well, since the participants should not be expected to provide an Operator with a blank cheque to do what it sees fit.

The document reflects this balance. Because of the increasing number of "long reach" Horizontal Wells, Subclauses 3.01E and 10.02H were introduced in the 2015 document to offer greater flexibility than the 75-metre radius test included in the 2007 document. These Subclauses grant an Operator increased flexibility by allowing for reasonable deviations in length or direction without invalidating the applicable AFE or Operation Notice. In essence, the Operator is to keep the bottom hole location within a radius of the greater of 75 metres or 7.5% of the original total measured distance of the Horizontal Leg from Heel to Toe, except insofar as is required to address drilling difficulties within the scope of Subclause 3.01D.

The onus is on the Operator to negotiate a broader discretion in the context of the particular well if it believes that the prescribed limitation is overly restrictive for the well or operating area. The Operator's ability to negotiate greater flexibility will be project specific. In practice, it will be a function of such factors as the nature of the project, the discretion being requested, the potential cost variance, the Operator's technical performance and its previous willingness to consult with the Non-Operators in a timely manner as conditions warrant.

The normal processes in Subclause 8.01A and Article 10.00 (i.e., Clause 10.07 and 10.08) otherwise apply to any Non-Participating Parties in a Horizontal Well, such that the participants in the well have some *bona fide* discretion to modify the scope of a proposed Horizontal Well without the potential invalidation of the original Operation Notice. The nature of this type of Operation is such that a Non-Participating Party takes this into account at the time of its initial election.

ii) The discretion granted to an Operator does not enable it to change the number of Horizontal Legs, such that additional approvals would be required to increase or decrease a program. This restriction probably would not have a significant impact in practice, though. The vast majority of Horizontal Wells will have only a single Horizontal Leg. For a Horizontal Well proposed to include multiple Horizontal Legs, an Operator would be most likely to modify the number of Horizontal Legs if the drilling results differed significantly from its anticipated outcome. The Participating Parties in the initial Horizontal Legs would typically be open to reconsidering the remaining program if the results were disappointing, where it is unlikely that any Non-Participating Parties would request a participation re-election because of a reduction driven by disappointing results.

Clause 10.08 would apply if the Operator subsequently proposed to increase the number of Horizontal Legs in a Horizontal Well under this Clause or Clause 8.02. The net effect is that additional Horizontal Legs could only be drilled in a well capable of production in Paying Quantities if the participants in the well agreed to that modification. The application of Subclause 10.08C to a Deepening would also provide any Non-Participating Party with a re-election right for the entire well. (See the definition of "Deepen" for the application of that definition to a Horizontal Well.)

Clause 8.02: The traditional "Casing Point election" will typically not apply to Horizontal Wells. If a well was initially proposed as a Horizontal Well, there is no point at which a Party must make its "Casing Point election". The decision to participate commits that Party to participate in the approved Operation. Clause 10.08 would apply to the Completion of the Horizontal Leg after that well was drilled, unless the Parties had previously agreed to the Completion program for the Horizontal Leg. The Parties are more likely to agree to a generic Completion program in conjunction with the drilling of a Horizontal Well in a mature area in which the nature of the Completion is known at the time the well is proposed, and Parties will potentially choose to address this in any custom provision they negotiate for the development of a Well Pad. This document did not go so far as to include a requirement to participate in a Completion of a Horizontal Well because of the residual uncertainty in drilling results, the more typical need to understand the well specific Completion program and the possibility that factors such as a change in strategy or funding restrictions could come into play.

On the other hand, a particular Horizontal Well may consist of the drilling of a Vertical Stratigraphic Wellbore and the possible kicking off of one or more Horizontal Legs from that Vertical Stratigraphic Wellbore, dependent on the initial results. The Parties then need to determine if they are prepared to incur the incremental costs for the applicable Horizontal Legs. The Article 9.00 processes apply, *mutatis mutandis*, to this decision point, such that a Party that is not prepared to participate in the proposed initial Horizontal Legs is potentially subject to a cost recovery for the incremental expenditures on the same basis as is prescribed in Article 9.00.

Subclause 8.02B is structured so that a Party cannot participate selectively in only some of the Horizontal Legs presented in the initial kickoff program. This reflects the difficulties in managing different ownership interests when production is commingled from multiple Horizontal Legs.

Article 9.00-General: This Article applies to wells drilled for the Joint Account. It also applies between the Participating Parties in an Independent Well because of Clause 10.16. It basically applies the provisions of the Operating Procedure on a *mutatis mutandis* basis between the Participating Parties, as if the Operation were their Joint Operation.

Clause 9.01: i) The qualifications in the first sentence were introduced in the 2015 document to address the possibility that the Parties have included special election provisions in their Agreement to address Multiple Well Drilling Programs, Multiple Well Completion Programs and the development of a Well Pad. Otherwise, the testing program described in the initial AFE for drilling the well (including a Deepening or Sidetracking) is the Operator's predicted testing program if the original assumptions are accurate. The setting of production casing/the associated Completion attempt is a distinct component of the overall Operation. The risk of proceeding with additional expenditures is reassessed after the evaluation of the logs and preliminary results. The inconvenience of consultation with the Non-Operators does not outweigh their right to determine the appropriate evaluation of their interests after the initial well results have been obtained.

ii) Pre-2007 versions of the document contemplated that every well would have a full Casing Point election, but this is not correct. There is no Casing Point election for a Horizontal Well, for example. It is increasingly common for participants in shallow Development Wells to agree that the scope of the drilling Operation can include the setting of production casing and the conduct of cased hole logs, assuming that the Operator will not be requesting a waiver of the logging requirement from regulatory authorities. It is also increasingly common for Parties to agree that the scope of the Operation can include: (a) the setting of intermediate casing above the target formation; (b) drilling into the target formation; and (c) the conduct of an open hole Completion if the wellbore has sufficient integrity. The provisions of this Article must be read in the context of what has been agreed to by the Parties as fundamental to the drilling of the agreed well to its proposed depth and those other expenditures that might be incurred after the well has been drilled to its target depth.

Clause 9.02-General: The 1990 document introduced greater flexibility in this election process for such matters as the handling of objections to the program, a proposed program limited to the setting of production casing and an election limited to setting production casing. This Clause must be read subject to the qualifications in Clause 9.01.

Subclause 9.02A: i) The Operator must promptly supply required logging and testing data to enable the Non-Operators to determine if they wish to attempt to set casing for production and further Complete the well. It must also supply them with a proposed program and an AFE for that program, so that they can make an informed decision about further investment in the well. The 2007 document was modified so that the requirement to supply information about the proposed program is satisfied if the Operator confirms that a contingent program (and associated costs) included with the drilling AFE still reflects its proposed program. This modification aligns the document much more closely to what happens in practice.

ii) The proposed program may be the setting of casing and the Suspension of the well, so that it may be re-entered later for a further unspecified Completion program. This reflects that the setting of casing for production is a specific subset of Completion, where references such as "further attempt to Complete the well" also reflect this construction. (The staged approach is often used in the deeper portion of the WCSB, where a service rig will often be used for the conduct of a testing program that is specified at that later time.) The Parties' approval of that initial program does not empower the Operator to re-enter the well later to attempt to Complete the well for their account without obtaining additional approvals under Article 10.00. However, additional approvals are not required if the program initially approved included the setting of casing and specifics of a subsequent testing program using a service rig shortly after drilling rig release and the testing program is Commenced on that schedule, subject to any application of the Force Majeure Article. (See Clause 10.08.) The Parties might sometimes agree to modify the timing for the latter for a winter only access area, but this would materially increase the uncertainty of the program cost presented for approval.

Subclause 9.02B: i) Each Non-Operator is to elect, within 24 hours after receipt of the required data and program information, if it will participate in the Completion attempt. This will be through a single step election under Subclause 10.02C, as supplemented by Subclauses 10.02D and E.

ii) The norm is that a Party has not approved an expenditure unless it takes action to confirm its approval, as in Clause 10.02. This Subclause is structured so that failure of a Party to reply to the Operator's notice is an election to participate in the proposed program, as in all previous versions of the document. This is because the logistics of this election process are that technical personnel will often be making decisions by phone outside regular business hours with no follow-up correspondence. The onus is on a Party that does not approve the program to document its election. The election was modified as of the 2015 document to be clearer that the deeming outcome is for a Party's Working Interest share of costs. The Parties would need to confirm the manner in which the costs of a Non-Participating Party will be assumed at the time. The document does not prescribe specific timelines in which this will occur. However, this is not as critical as may first appear because the decision being made at this time will usually relate to the stabilization of the well for a subsequent Completion under Clause 10.08. That being said, the Operator will be very motivated to resolve the cost allocation quickly if it is not prepared to assume its share of all available interest in the well.

iii) A participant is deemed to have approved the proposed program unless it otherwise notifies the Parties in the election period. If the Operator proposes to alter its program materially because of an objection, each Party may re-elect, as the program would differ materially from that to which the election pertained. The Operator would likely convene a meeting to attempt to resolve the issue if there were a significant difference of opinion.

The 1990 document expressly addressed the possibility of objections to the proposed program. (Objections would have been made on an "offline" basis under previous versions of the document.) This provides a platform to raise issues. However, it sometimes may be less than satisfactory, as there is no mechanism that compels closure if the Parties are unable to agree on the handling of the objection (e.g., perforation of a water bearing formation). This is largely because of the timing logistics associated with this type of Operation.

iv) A Party that disagrees with the specifics of the Operator's Completion program can limit the negative impact on it by participating in setting casing. Otherwise, the production casing costs go into the cost recovery. The 2007 document introduced some additional flexibility by expanding the divided well process in Clause 10.05 to apply to Completion programs, so that participation can be limited to development objectives.

If at least one of the other Parties proceeds to conduct the full Completion attempt at that time, a cost recovery prescribed by Clause 9.03 would be based only on that portion of the costs not assumed by the Party that limited its election.

v) The Operator's proposed program might be an evaluation of more than one formation. Without a negotiated outcome (or in the post-1990 documents, use of the Clause 10.05 divided well process), a Non-Operator has limited ability to participate selectively. The issue is more complex if it includes any component that is contingent on other aspects of the program. If the additional test is contingent on another test being successful, it is difficult to argue that a Party should be able to participate only in the (lower risk) contingent test. A good argument can be made that this should not apply if the additional test is contingent on a prior test being unsuccessful, as the risk for the unrelated test has not been reduced. Other than for the modification to Clause 10.05, the document does not address these issues specifically because of the multitude of potential permutations and cost allocation issues. It is preferable that Parties facing this issue retain flexibility to explore negotiated outcomes that reflect their situation and their ongoing relationship. Key aspects include: (a) wellbore ownership issues; (b) cost allocation issues; and (c) indemnification and liability.

Subclause 9.02D: i) Clause 3.04 requires the Operator to conduct Operations "diligently". Suppose that the Operator obtains approval for a Completion attempt, and proceeds only to set production casing, with the intention of conducting the remainder of the Operation at an indefinite date. To what degree can the Operator rely on the original approvals of the Parties to participate in the Operation? In some instances, Clause 3.04 may allow the Parties to claim that the Operator is required to obtain additional approvals, particularly if the AFE included a statement about the intended Completion date and there was no reasonable technical justification for the delay.

If the Operator had stated in the AFE that the Completion attempt was to be conducted within a specified period after the setting of production casing (as contemplated in Subclause 9.02A), the Non-Operators might also attempt to argue that a material deviation from that representation voided their approval of that portion of the AFE, particularly if there were some business sensitivities to the timing of the outstanding work (e.g., expiries, land sale). (See the reference to the Passburg and Prairie Pacific cases in the annotations notes on the definition of AFE.)

It is not appropriate to include an arbitrary termination mechanism, however, because of the multitude of potential fact situations.

ii) Clause 10.08 will apply to the Participating Parties with respect to subsequent Operations on the well.

Clause 9.03: i) A Non-Participating Party is subject to a cost recovery. Pre-2007 versions of the document included a cost recovery under Alternate A or a forfeiture under Alternate B. Alternate B was deleted from the 2007 document because it was used so infrequently.

ii) The cost recovery percentage will depend on the applicable formation(s) being in a Development Well or an Exploratory Well. The 1974 and 1981 documents applied only the Development Well penalty. This created a result that was inconsistent with the handling of Recompletions under the comparable versions of Clause 10.08, so the 1990 document was modified on this point.

iii) Pre-2007 versions of the document were unclear about the interrelationship between Clauses 9.03 and 10.10 when the well was a "Title Preserving Well". The application of the risk-reward test dictates that a Party that participated in the well should still be subject to a forfeiture under Clause 10.10 if it does not participate in any Completion program required to retain a portion of the Joint Lands. This reflects the fact that it ultimately is not participating in the Operation required for retention of the "Preserved Lands". (The Clause 9.03 penalty mechanism would apply to the Title Preserving Well, though, if land retention were not contingent on Completion (e.g., Alberta licence validation).)

The application of the general Clause 10.10 outcome admittedly creates the result that a Party that paid its full share of Drilling Costs would ultimately be worse off than would have been the case had it initially simply chosen not to participate in the Title Preserving Well. While this may at first appear to be a harsh result, the option to make an informed election at Casing Point is of significant value, and each Party knows the rules at the time it makes its participation elections for the well and at Casing Point. In practice, a Party that participates in the drilling of the Title Preserving Well in this circumstance would typically be very motivated to participate in any Completion attempt if there were any reasonable encouragement. This is different than the situation in which title preserving work is conducted in a well in which a Party is already subject to a cost recovery.

Clause 9.04: i) Subject to any application of the Force Majeure Article, a wellbore Abandoned within six months after the Casing Point election will generally be Abandoned for the Joint Account of the drilling Parties. This is subject to qualifications for additional costs resulting from the Completion attempt, the charging of anticipated surface restoration costs and the application of the proceeds from salvable material to the cost recovery account, as in Subclause 10.09B. If the well is Abandoned prior to the cost recovery, it will be for the account of the Parties that participated in the setting of production casing/Completion. If it is Abandoned after the cost recovery, it will be by Parties then having interests in the well.

ii) The handling of Abandonment responsibility in the 1974 and 1981 documents was not clear, as the proviso included in the text of Alternate 903B therein was intended to apply to both Alternates A and B, not just B.

iii) Operational logistics are such that the six-month time period will be modified for some operating areas.

Clause 9.05: A Completion attempt by fewer than all Parties is really just a special type of Independent Operation. Without this Clause, users might not remember that the principles in such provisions as 10.15, 10.16, 10.17, 10.18, 10.19 (information) and 10.20 also apply to Article 9.00.

Article 10.00 - General: The paramount policy objective of an Operating Procedure is to encourage the joint evaluation of the Joint Lands. It is important to place it in a practical perspective, though. The investment strategies of the Parties will often differ with respect to the nature or timing of a work program and internal budget thresholds. In practice, those differences will often (but not always) be resolved through negotiation. An Operating Procedure, therefore, must include some mechanism for resolution of these differences - an Independent Operations provision.

The fact that the strategies of the Parties may differ is not inconsistent with the underlying objective of encouraging Joint Operations. The Independent Operations provision, therefore, should not include consequences for non-participation that are chosen so that an Independent Operation will not be a practical alternative. The Parties will probably have different business strategies from time to time. Parties must structure an Agreement accordingly, to neither encourage nor discourage an Independent Operation if differences cannot be resolved through negotiation. The attempt to balance the recognition of risk and reward is the foundation of this Article.

The Article is designed to address the vast majority of transactions. There may be situations in which the nature of the contemplated Operations warrants significant modifications. Parties pursuing a high-risk, high-reward play in a large wildcat area might, for example, include some sort of forced farmout mechanism for non-participation in Exploratory Wells meeting certain criteria in at least the initial stages of their exploration program. (See the miscellaneous annotations in the Addendum at the end of the document for additional insights on this issue.)

Clause 10.01: i) An Independent Operation is one that is proposed as such under this Article. It may ultimately be conducted for the Joint Account.

ii) A Party that elects not to participate in an Equipping (10.08F) or a Production Facility (10.13B) is only a Non-Participating Party if a cost recovery applies to it. This does not occur if it elects to take its production in kind or, under Subclause 10.13B only, it elects to pay the applicable usage fee.

iii) An Operation Notice should include all non-proprietary information that would reasonably be expected to be material to a Party's decision to participate. It does not require a Proposing Party to share its economic analysis or technical interpretation of the prospect. The proposed location of a well must be specified in reasonable detail. (See the definition of AFE and the related annotations.)

iv) See the definition of Development Well and the related annotations to understand the evolution of this definition over time.

v) The Proposing Party is required to state any expected application of the Clause 10.10 title preserving processes in the Operation Notice, including a description of the Joint Lands (areal, stratigraphic) to which it expects that Clause 10.10 would apply. Some Operation Notices issued under older versions of the document simply referred to a well as a Development Well or an Exploratory Well when the applicable penalty was actually found in Clause 10.10. That practice is misleading. The importance of specifying the Joint Lands expected to be included in the Clause 10.10 forfeiture is particularly important if there may be another basis to extend at least some of the Joint Lands subject to the applicable Title Documents. There will be other circumstances in which failure to specify the applicable Joint Lands should not compromise the effectiveness of the Operation Notice (i.e., clear that the well is the only basis by which the applicable Joint Lands may be extended).

The expected application of Clause 10.10 identified in the Operation Notice and the actual application of the Clause may be different, as the Operation Notice cannot give greater rights to the Participating Parties than those provided under that Clause. Subclause 10.10H includes a dispute resolution process if there is a dispute about the potential application of that Clause. As noted in the annotations on that Clause, the issue is ultimately a question of fact in each particular case. At the end of the day, what work entitled the applicable rights of the Joint Lands to be retained? Insofar as there is a dispute about the potential application of the Clause, there is nothing in the document that allows a Party to defer its election or otherwise claim that the Operation Notice is invalid. Any such process step would encourage passive Parties to object to each Operation Notice to which Clause 10.10 is purported to apply. It is, however, beneficial to identify any objections in a timely manner, as this facilitates a negotiated resolution in due course and timely exploration of such possible alternatives as an advance ruling submission under the Regulations.

vi) Clauses 10.05 and 10.06 include additional information requirements if the well is only in part a Development Well or it will be (or has been) used for other than the Joint Lands.

vii) There will be situations in which the information provided with the Operation Notice is so deficient that it does not meet the document requirements. The document could include a prescriptive checklist approach, where the absence of any of the stated components would necessarily invalidate the notice without regard to materiality. Another approach is to avoid defining the point at which an Operation Notice becomes ineffective because of either the lack of certain information or, as is more likely the case, the inclusion of insufficient information, particularly the accuracy of the AFE information. The second approach has historically been used, as this assessment is ultimately based on the circumstances and the belief of the various authors that the first approach would often see notices rejected on a technicality.

The Parties should be clear about their expectations for rectification if a particular Operation Notice is so deficient that it is ineffective. The best approach is often to reissue it, as this provides the greatest certainty. Provision of the missing information may sometimes be preferable.

A joint CAPL-CAPLA Committee initially prepared precedent materials on Operation Notices in 2006, and updated versions of those documents are available on the CAPL and CAPLA websites. The materials were prepared as a reference package, to assist users to improve their understanding of the requirements in the various versions of the document and to optimize their internal precedents. The package includes: (a) an annotated precedent Operation Notice; (b) a precedent without the annotations; and (c) specific examples for: (1) a new well; (2) a Completion; (3) an Equipping; (4) a Sidetracking; and (5) a Production Facility. There is no requirement to use these materials, given user preferences for their own formats and the need to customize an Operation Notice to the particular situation.

viii) A Party subject to a cost recovery due to non-participation in a well generally does not have the status of being a Receiving Party for the Completion or Equipping of that well. An Operation Notice for any such Operation would be served only to the Participating Parties in that well, as the existing Non-Participating Party generally has no right to participate in that Operation. (See also Subclause 10.08B.)

There are four qualifications to that general outcome. The first is that a Party that participated in only the Development Well portion of a divided status well for which it then received reimbursement under Paragraph 10.05C(b) will have the right under Subclause 10.07B to participate in a Recompletion in the reimbursed interval if the Exploratory Well portion of the well is Abandoned prior to the cost recovery. The second is that a Party that participated in drilling and setting production casing may participate in a Recompletion under Subclause 10.08B after an unsuccessful Completion in which it did not participate. The third is that a Non-Participating Party will have the opportunity to re-elect with respect to a Deepening or Sidetracking under Subclause 10.08C, to reflect the change in scope relative to what was originally proposed. The fourth is that a Non-Participating Party may have re-election rights at law or equity in certain circumstances in which the scope of the presented Operation differed materially from the Operation that was actually conducted. (See the annotations on the definition of AFE in Clause 1.01 and the second annotation on Subclause 10.07A.)

Subclause 10.02A: i) The qualifications in the first sentence were introduced in the 2015 document to address the possibility that the Parties have included special provisions in the Agreement to address Multiple Well Drilling Programs, Multiple Well Completion Programs, development of a Well Pad and potential restrictions on the activities that may be conducted by a Party on a Well Pad. This change and the similar changes in other provisions were included to minimize the need for consequential changes resulting from the inclusion of any such negotiated provisions. (See also Clause 10.04 with respect to the possibility that there could be restrictions on the ability of a Party to conduct Operations on a particular Well Pad.)

ii) A Party may issue an Operation Notice without prior advice to its co-venturers. This largely reflects the logistics of attempting to manage numerous properties and agreements, as well as scheduling and resource logistics. (Pre-2007 versions of the document included a sentence that the Parties would normally consult about decisions for the exploration, development and operation of the Joint Lands. It was deleted from the 2007 document because it was typically given little or no weight by Parties.)

However, a Proposing Party will often first alert them to its intention to issue the notice, particularly if there is an active delineation or development drilling program. This practice has several benefits. It encourages an exchange of ideas, something that would likely be attractive unless a Party is pursuing its individual agenda for a regional play. It enables the Proposing Party to gauge the degree of support for the Operation prior to issuing its notice and the allocation of its resources to the Operation. It also provides the other Parties with additional time to obtain funding or a farmee.

iii) Clause 3.01 (financial authorities) and Clause 7.01 (pre-Commencement approvals) do not force a response to an AFE within any specific time. It is the better practice for an Operator to issue an Operation Notice if: (a) time is of the essence, to ensure that there is a consequence associated with the response; or (b) there is a concern that a Party may reject the AFE and issue its own Operation Notice in order to operate the Operation.

iv) A Party receiving an Operation Notice has a legitimate expectation that it is presented with an investment opportunity from which it can receive a financial return. Should a Proposing Party be able to serve an Operation Notice for an additional well on a section on the assumption that an application for a holding or other modification to a Spacing Unit or drilling density will be approved under the Regulations in due course?

After considering various alternatives, the conclusion was that the normal notice and response period (including any application of Subclause 10.02F) applies if an Operation Notice is served for a well for which regulatory approval of that type of application is required, provided that the application has been made under the Regulations and has not been rejected thereunder. This reflects the assumption that these applications are typically approved in due course (perhaps with a different drilling density) and that Operations should not be frustrated during the period prior to receipt of the approval.

A rejection of the application by regulatory authorities terminates the Operation Notice and the elections thereunder. Although objections to the application do not have the same effect, the Participating Parties should proceed cautiously if there are objections to the application, as objections may increase significantly the risk that the application may ultimately be rejected.

Subclause 10.02B: i) It is the better practice to send a copy of the election to the Proposing Party and the other Receiving Parties. A Receiving Party's election is effective if made only to the Proposing Party, to avoid any potential question about the validity of a response served only to the Proposing Party. Providing the response to all Parties allows them to understand the likely cost allocation earlier in the process, and simplifies the potential application of Subclause 10.02D. The last paragraph of Subclause B in the post-1990 documents includes a requirement to provide a copy of the response to the other Receiving Parties, while being clear that the response is not invalidated for failure to comply with this requirement.

ii) The qualifications in the first sentence were introduced in the 2015 document to address the possibility that the Parties have included special election provisions in the Agreement to address Multiple Well Drilling Programs, Multiple Well Completion Programs and the development of a Well Pad. Otherwise, the general reply period to an Operation Notice is within 30 days after its receipt, subject to three exceptions to that timing.

Firstly, the response period is reduced to 15 days if the Operation Notice pertains to a well and certain P&NG rights have been offered for sale by the Crown within 60 days after its receipt. Those sale rights must: (a) be within 1.6 kilometres of the proposed well; and (b) include at least one formation that corresponds to the formations to be evaluated by that well. The 60-day period is well aligned with the period between publication of a sale notice and the sale date (e.g., currently 56 days in Alberta). The reference to formations to be evaluated by that well was introduced in the 2007 document. It recognizes that a Cardium test on section 1 would have no relevance to a section 2 parcel of rights below the top of the Wabamun. It is also clear as of the 2007 document that there has to be a reasonable expectation that some of the rights included in the sale parcel would be evaluated prior to the sale. It would be very difficult for a Party to argue that it meets this requirement if it has not applied for its well licence until a week before the sale or it was intending to Spud a well to evaluate a deep rights only parcel two days before the sale. While the existence of an area of mutual interest is not a pre-requisite to use of this mechanism, there would be a practical motivation to consider a joint bid in many circumstances.

Secondly, the response period will only be 48 hours if the proposed Operation is a Clause 10.08 Deepening, Sidetracking, re-entry and Completion, Recompletion or Reworking <u>and</u> the rig to be used for it is then at the well location for the conduct of other Operations. This is because the standby costs are such that time is of the essence if a Party wants to propose such an Operation while the rig is on location. The condition that the rig is on location for a prior Operation was introduced in the 2007 document because of some abuse in the previous version. Parties sometimes provided no prior notice of their intention to move a rig to the location to create a surprise 48-hour election, in the hope of maximizing their interest in the well.

Thirdly, the response period will be seven Business Days if the proposed Operation is under Subclause 10.06C (a well imported into the Agreement after being used for another purpose) when the rig to be used is then on location for prior work on the well, as under Paragraph (b). From the perspective of the Proposing Party this may seem to be too long when a rig is on site. It is important to recall, though, that the Receiving Parties may have had no prior knowledge that there was any vision of importing this well into the Agreement. This timing is designed to reinforce to the Proposing Party the benefits of prior dialogue with the other Parties. This would alert them that the well is being drilled and the contingency that Subclause 10.06C might come into play if the well is unsuccessful in the 100% rights and there is apparent prospectivity in a formation of the Joint Lands.

iii) Suppose that the Proposing Party Spuds a well before expiry of the 30-day election period and decided to Deepen it before expiry of that period. Should it have the unilateral ability to require a Receiving Party to elect before expiry of the original election period? Paragraph (b) was modified in the 2007 document so that it is clear that the Proposing Party cannot require an election on the Deepening prior to the election under the original election period. A Proposing Party must proceed carefully if its Operation will be complete before expiry of the second election period. It would find itself in a very awkward position if a Receiving Party elected to participate in both components when it had already Abandoned the wellbore.

Subclause 10.02C: i) Assume that the Working Interests are A1%, B24%, C25% and D50%. B issues an Operation Notice for a well, and A is willing to participate for a 2% interest. Under the traditional provision (i.e., Clause 1015 of the 1981 document), A was required to participate to the extent of its Working Interest (1%) or for its proportionate share (4% if C and D elect not to participate). The corresponding provision in the 1990 document introduced much greater flexibility. A Party may elect to participate for its Working Interest, its proportionate share of all available interest or its proportionate share of all available interest with a limit on the maximum percentage of Participating Interest.

ii) Failure to limit the Participating Interest in the Operation Notice or the response is deemed to be an election to assume a proportionate share of all available interests. While the form of the election mechanism differs, the outcome is the same since the 1990 document.

iii) A Party does not have the right to participate for less than its Working Interest, so it would need to negotiate that outcome if it wanted to do this.

Subclause 10.02D: i) If even one Party elects to assume its proportionate share of all available interest under Paragraph C(b), the interests will be fully subscribed. If there is an unassumed percentage of participation after the process in Subclause C, the Participating Parties will need to allocate the unassumed interest within a prescribed time or the notice will be deemed to be withdrawn.

ii) Assume that the interests are fully subscribed. What are the respective legal rights of the Parties if the Proposing Party unilaterally determines that it no longer wishes to conduct the Operation? A Proposing Party should proceed cautiously if it is unsure if it will actually drill the well, particularly if there is a pending expiry or a competitive drainage situation. This is a particularly interesting question if the Proposing Party had no genuine intention of drilling the well and could benefit from not proceeding with the well (e.g., competitive drainage situation).

Subclause 10.02E: The Proposing Party is to notify the other Parties of the cost allocation if fewer than all Parties elect to participate. This provides clarity about the manner in which costs are borne and the reward shared. This information is often unclear in land files and in land information systems, and creates confusion in divestitures. An AFE updating the interests might also be issued, but it is only for informational purposes.

Subclause 10.02F: i) The qualifications in the first sentence were introduced in the 2015 document to address the possibility that the Parties have included special election provisions in the Agreement to address Multiple Well Drilling Programs, Multiple Well Completion Programs and the development of a Well Pad (e.g., no right to defer responses under this Subclause for Development Wells being drilled to the target formation on a particular Well Pad.) Otherwise, a Proposing Party may propose an unlimited number of Operation Notices at any time. Protections have been included for the Receiving Parties, subject to optional Subclause 10.02G, which was included to facilitate the conduct of shallow infill programs.

An Operation Notice may not be for multiple wells, so the Parties are not required to commit to a regional strategy or an all or nothing package.

ii) The commencement of the response period for an Operation Notice can be deferred if there is certain other well activity being conducted on the Joint Lands at a location within 3.2km of the location of the proposed Independent Operation. (The distance was 3.2km in the 1990 document and three miles (4.8km) in the 1981 document. The distance calculation was adjusted as of the 2015 document to be clear that a measurement involving at least one Horizontal Well was between the nearest points of the respective wells in the applicable formation, such that the entire Horizontal Leg is taken into consideration, rather than only the Toe. This is consistent with the approach used to determine if a well is a Development Well.) Paragraphs (a) and (b) outline the types of well activity that result in a deemed deferral of receipt.

Paragraph (a) was introduced in the 2007 document. It allows for the deferral if another well has been approved to be drilled, Completed, Recompleted or Reworked for the Joint Account under either an AFE or another Operation Notice. This recognizes that the participation decision is likely to be influenced by the results from the Joint Operation. It also ensures that the impact is the same if the Joint Operation were approved through an AFE or in response to an Operation Notice. While the Operation would usually pertain to a different well, it could also pertain to the same wellbore. In essence, it sees each Participating Party being treated as if it were the Proposing Party.

Paragraph (b) allows for the deferral with respect to activities under a previous Operation Notice issued by <u>that Proposing Party (or its Affilate)</u>, if the activity has not then been approved for the Joint Account.

If Paragraph (a) or (b) applies, the Receiving Parties are generally deemed not to have received the Operation Notice until the pre-existing AFE or Operation Notice: (a) has expired; (b) has been withdrawn; or (c) is no longer in effect because the Operation was conducted. If the latter, it may also delay its response until receipt of any well information under Clause 10.19, basically well information from all wells on the Joint Lands insofar as Subclause 10.08C or Clause 10.10 do not apply. The requirement to release information ensures that the Non-Participating Parties are not effectively penalized in the evaluation of other opportunities on the Joint Lands. A prudent Proposing Party might choose to alert the Receiving Parties when the applicable response period commences, particularly if the layering of Operation Notices is complex.

Clause 10.08 includes some restrictions on issuance of an Operation Notice that are addressed in the annotations on that Clause. The post-1990 documents are clear that a Participating Party in the well is not deemed to have received an Operation Notice for an Equipping until it has access to the Completion information from the well. While there may be good reasons to initiate some work on the tie-in sooner (i.e., wildlife or access considerations), it is not appropriate to enable an Operator to trigger responses before Completion information is understood. Consultation is preferred for those cases. The 2015 document introduced a similar requirement for a proposed Production Facility-the Operation Notice is not deemed to have been received until each Receiving Party has received the Completion information from at least one of the wells being served by it.

iii) A Receiving Party's right to delay its response to additional Operation Notices under Paragraph (b) has limited application if a different Party is otherwise the Proposing Party for the second Operation Notice. Suppose, for example, that A, B and C are the owners of a three-section block, and A and B each issue an Operation Notice for a well. Subject to Clause 10.19, the notices are processed independently, as each Party, as an owner, has an equal right to propose its own independent drilling program. This is not intended to encourage Parties to agree on a common path and use different Proposing Parties only to alter the rights of the passive Party.

iv) The post-1990 versions of the document are clearer about the interrelationship between this Clause, Clause 10.10 and Paragraph 5.05B(b). A Receiving Party cannot defer its election for a well to which Clause 10.10 or the withholding of information under Paragraph 5.05B(b) applies.

Subclause 10.02G: i) The restrictions in Subclause 10.02F are sometimes overly restrictive. Large sequential infill drilling programs are common for low-risk shallow gas/tight gas and heavy oil projects if the variation in results between wells is expected to be minor. The Operators of those programs usually prefer to treat those wells as a single project to optimize project efficiency, the construction of associated project infrastructure and the program cost. They will often be reluctant to sacrifice the program waiting for elections on a well-by-well basis from a Receiving Party.

This optional Subclause substantially addresses the issues relating to shallow programs, and may often enable an Operator to obtain agreement to handle a program under a single AFE in practice. The Parties should elect that this Subclause will apply if this type of program is expected. (An amendment should be considered if it was not selected and the issue arises after execution.) While Receiving Parties may still elect on a well-by-well basis (rather than on an entire program), they cannot defer their elections until they see results from other wells in the program. Although a Receiving Party may elect not to participate in a particular well, this is likely to be the exception because of the nature of shallow infill programs.

ii) Some Parties might modify the document to limit the number of wells or the estimated costs that could be proposed in a program.

iii) The subsurface reference was replaced in the 2015 document by a formation reference, with a possible Head Agreement formation definition.

iv) A variation would be the inclusion of a customized provision to address a deep Development Well drilling program, particularly where the wells are being drilled from a common drilling pad. Any such provision could address such items as: (a) the permissible number of wells in a program and the identification of their sequencing; (b) the individual rights of election for each well; (c) the ability to defer the response (for at least the Participating Parties in the immediately preceding well) until a short time after receipt of the drilling and logging information from the preceding well; and (d) expectations for the manner in which surface costs and associated liabilities would be shared between wells using a common surface location. The Parties would also need to consider the rights, if any, of a Non-Participating Party in the preceding well to have the benefit of well information from that well when making its election on a subsequent well in the previously identified "program". Further customization may be required to address the interrelationship between that provision and Article 8.00 for Horizontal Wells. The level of project specific customization was such that it was not feasible to include this type of provision in the document.

Subclause 10.02H: Subclause 3.01D clarifies that certain activities are inherent in approval of an Operation, and Subclause 3.01E outlines the limit before the consent of a Participating Party is required. Subclause 10.02H prescribes the authority to proceed with modifications to the well location before the Non-Participating Party's election rights are potentially triggered under Subclause 10.08C or otherwise at law. Subclause 10.02H is largely built on Subclause 3.01E, with Paragraphs 3.01E(f) and (g) modified for this purpose to grant greater discretion relative to the Non-Participating Parties than the corresponding thresholds in those Paragraphs. Largely because of the nature of foothills wells, the restriction on the ability to conduct a plugging back and Sidetracking in Subclause 3.01E is not applicable to Subclause 10.02H and the obligations of the Participating Parties relative to the Non-Participating Parties with respect to the modification of an Independent Well that otherwise satisfies the requirements in this Subclause.

See the annotations on Subclauses 3.01D and E for additional insights on this Subclause. The onus is on the Parties to assess the suitability of Subclauses 3.01E and 10.02H for their particular circumstances. The Parties will sometimes choose to delete Subclauses 3.01E and 10.02H or to modify the variance thresholds in Paragraphs 3.01(f) and (g) and 10.02H(a).

Clause 10.03: i) The interpretation of "commenced" was unclear in pre-2007 versions of the document, so it was been defined as of the 2007 document. For new wells, it is the Spud date. (See also the definition of Commenced and the related annotations and annotation (iv) below.)

ii) The post-1990 documents include a proviso that a Proposing Party must issue an Operation Notice before Commencing an Independent Operation. (This can be prior to the start of the response period if there is a deemed delayed receipt under Subclause 10.02F.) As a Proposing Party might do this inadvertently in situations in which there is no actual harm to the Receiving Parties, the Clause 10.02 response process still applies to any such Operation Notice for a Commenced Operation. However, the Receiving Parties would retain any legal remedies they may have for failure to serve that Operation Notice prior to Commencement of the Operation. That proviso is designed primarily to protect Receiving Parties against potential abuse if a Party tries to obtain exclusive well data to position itself for a Crown sale or a farmin. A Party facing this issue would often attempt to seek injunctive relief if it believed that its interests were being prejudiced. In the absence of harm, it is unlikely that a Party that innocently Commences an Operation early would face problems under this Clause in practice.

A Party that perceives that it has suffered damages because of failure to serve an Operation Notice before Commencement of the Operation should promptly notify the Proposing Party and the other Parties about the nature of its concern. Failure to provide that notice promptly could adversely impact its ability to pursue a claim because of the legal doctrines of "estoppel in pais" and "laches" (basically potential limitations on the ability to assert rights when others have relied on your conduct to their detriment) and the duty on an injured party to mitigate its loss. It was not feasible to include a specific time limitation on the ability to serve such a notice because of the possibility that the damage may not initially be apparent (i.e., Proposing Party used information from the well to acquire a freehold lease under the name of a third party agent).

iii) Operations are often Commenced before expiry of the response period if there is: (a) an early receipt of elections; (b) a low-risk infill drilling program if Subclause 10.02G does not apply; (c) immediate access to a rig; or (d) a long duration well in an area with a short operating window.

The Operator of a well that is not expected to encounter the primary or secondary targets within the response period may prefer to Commence it earlier. This will particularly be the case if: (a) it is prepared to assume all available Participating Interests in the well; (b) risks for the initial portion of the well are low; and (c) operational logistics are tight (e.g., seasonal access, pending Crown sale, availability of suitable equipment). Conversely, a prudent Proposing Party would not Commence a well prior to expiry of the response period if the information was highly variable, the well was expected to be of short duration and the Receiving Parties could alter their risk by scouting the well.

iv) Subject to Force Majeure, the Proposing Party is to Commence the Operation within 120 days after issuance of the Operation Notice (90 days in the 1990 document), with a 30 day increase for Production Facilities and greater flexibility for an Operation committed to under the B.C. Regulations in order to obtain an extension to a Title Document. (For context, the Parties are not required to "commit" to any work to obtain a temporary Section 17 continuation in Alberta.) It should be cautious in unilaterally choosing not to Commence the Operation within that period, particularly where it is advantageous not to see it conducted (e.g., competitive drainage situation). As noted in the annotations on the definition of Commenced in Clause 1.01, the Parties should consider customizing this provision to increase this period if it is not appropriate for their project area.

v) Production Facilities have a longer period because of the logistics of obtaining approvals and the design and construction process.

Clause 10.04: i) Prior to the 1990 document, the Operator would conduct the Operation if it elected to participate. This was modified in the 1990 document, so that it was similar to Alternate A(a), by having the Proposing Party at least initially conduct the Operation.

ii) The shared use of Well Pads for wells drilled by different ownership groups is an emerging issue. Field logistics and regulatory restrictions respecting Occupational Health and Safety are such that agreements for the use of shared Well Pads will often include restrictions on the ability of a Party other than the site operator of the shared Well Pad to conduct Operations on the shared site. The first sentence was introduced in the 2015 document to recognize this potential outcome, and reminds users of the need to be aware of any such agreement for use of a shared Well Pad. The Parties should ensure that any such other related agreement is identified clearly in the comments section of their land information system.

Alternate 10.04A(a): i) This Alternate recognizes that: (a) the Operator may have planned to allocate its personnel to other projects; (b) it may not be able to operate under the proposed timing and cost constraints; and (c) Non-Operators typically have the expertise to conduct most Operations. The Non-Operators may not want the Operator to conduct the Operation if they are confident that the Proposing Party can conduct it properly for the cost in the AFE or they doubt that the Operator could conduct it on a similar schedule for a similar cost.

ii) To ensure a Proposing Party is accountable, it will conduct the Operation unless: (a) it is in default under Clause 5.05 (ultimately a question of fact-mere issuance of a default notice is not necessarily determinative); or (b) it would be disqualified from operating by Subclause 2.02A. The Parties always have the option to agree to a different outcome at the time.

iii) An Operator that is not eligible to receive a well licence transfer in due course is subject to immediate replacement under Paragraph 2.02A(f).

iv) Notwithstanding the general provision, the Operator would probably conduct certain Operations. If there were safety or other technical concerns about a particular Proposing Party's expertise (e.g., critical sour gas well), the other Parties might attempt to negotiate an alternative arrangement. (They may choose to do so in their initial negotiations for foothills type agreements in any event.) If the rig is on location, the Operation is the setting of casing or a Deepening or Sidetracking and the Operator is not prepared to participate, the Operator would probably conduct it under a contract operating arrangement because of the desire for technical continuity and the difficulty in transferring supply contracts and regulatory approvals. However, this mechanism is not included in the document because of the need for Parties to address it on a custom basis at the time.

Alternate 10.04A(b): i) This Alternate is similar in many ways to the Clause that had been included in the 1981 document, but has additional flexibility if the Operator does not elect to conduct the Operation in its election to participate. There were two major reasons for including this Alternate. Firstly, some users had amended the 1990 document to use the provision from the 1981 document. Secondly, the Operator's particular technical expertise may be of such benefit that the Parties want the Operator to conduct each Operation in which it participates. This may particularly be the case, for example, in the foothills, in certain critical sour gas, shale or tight gas areas or in other projects requiring highly specialized technical expertise.

There is a critical difference, though. An Operator that elects to conduct an Operation is required to do so in substantial compliance with the Operation Notice (e.g., schedule, scope of Operation, any specified technical program, etc.). It may not impose its own vision for the Operation.

ii) An Operator considering the exercise of its rights under this Clause must also assess its ability to obtain contracts for required goods and services. The Proposing Party is not obligated to transfer any contracts for goods and services that do not pertain exclusively to the Operation.

iii) An Operator that exercises its takeover right and then fails to proceed with the Operation may not exercise its takeover right again for that Operation (or a substantially similar Operation) proposed in an Operation Notice within 365 days after the original Operation Notice.

Subclause 10.04B: Subject to Alternate 10.04A(b), an Operator that is a Participating Party (but not the Proposing Party) has the option to succeed the Proposing Party as Operator at completion of the Operation (e.g., after conclusion of any program proposed at Casing Point under Article 9.00) or that particular phase thereof as the Proposing Party and the Operator may agree. (If an Independent Well is being Abandoned by the Proposing Party, it will retain responsibility for the entire Abandonment process, unless otherwise agreed with the Operator.) While the Operator will typically exercise its right to take over the Operation in due course because of the potential synergies with other Operations, this will not always be the case.

Subclause 10.04C: A Proposing Party other than the Operator could be the Operator of that Operation through Clause 10.04, the definition of Operator and Clause 10.16. The extension of these rights and responsibilities to a Proposing Party other than the Operator is limited to the particular activity and does not otherwise alter the Operator's overall responsibilities.

Subclause 10.05A: i) A well may be in part a Development Well and in part an Exploratory Well. In those instances, it is accepted that a Party should be able to limit its participation in the drilling or (new as of the 2007 document) Completion of the well to that portion which is a Development Well. This reflects the view that it would be inappropriate to deny a Party the right to participate in the exploitation/evaluation of a development play because it was not prepared to participate in unrelated exploratory activities. The mechanism does not allow a Party to limit its participation in an Exploratory Well to the V formation when the well is intended to evaluate the Z formation because of the practical implications of such an extension. However, there are circumstances in which the Parties may wish to negotiate this outcome.

ii) Failure to issue an Operation Notice on the prescribed basis would be a clear breach of the Article and enable the Receiving Parties to reject it as invalid. The outcome is not clear if they make elections under the initial Operation Notice and later discover the problem.

iii) The Operation Notice and the associated AFE are to provide sufficient information about the respective portions of the well to enable an informed election under Subclause B about such matters as formations, material differences in downhole locations and cost allocations.

iv) Note the reference to specialized equipment or casing. If, for example, special equipment or casing is required because sour gas might be encountered in the exploratory portion of the well, those costs would not be relevant to the development portion of the well.

Subclause 10.05C: i) Disputes about the allocation of costs are included in the list of items that can be resolved by arbitration under Article 21.00.

ii) A Party is not prevented from drilling a twin well to exploit the "development" formation while the cost recovery applies to the "exploratory" Spacing Unit. (See Paragraph 10.07A(e), Subclause 10.07B and the related annotations about a Paragraph 10.05C(b) reimbursement.)

iii) The reimbursement under Paragraph (b) is only made if the well is productive in both portions, but it cannot be produced simultaneously. It is designed to position the Development Well participants to drill a twin well to the prospective Development Well formation if they are so inclined. This mechanism and the subsequent potential uphole participation rights of the former Development Well participants are addressed in Subclause 10.07B.

iv) The Parties will need to supplement this provision at the time if production will be commingled. They would need to address such matters as testing obligations to confirm that the production allocation continues to be reasonable and the process for making any required adjustments.

Clause 10.05-Other: i) Given the complexities potentially associated with this Clause if the participation in the well differs, the affected Parties may find it helpful to supplement the Clause with a letter agreement that addresses more specifically the outcomes in their particular situation.

ii) The traditional provision has not provided any corresponding process for a Development Well that is prospective in two or more formations that are productive in prior wells within 3.2km of the location. A Receiving Party's choice has been to participate in the entire well or elect not to participate, such that it can be required to participate in drilling and Completion activities of little interest to it to maintain its rights for its primary objective. A Receiving Party has retained the ability to propose a shallower well for its preferred objective, though. If faced with this situation, a Receiving Party might try to negotiate the application of the Clause 10.05 dual election process to that well. A prudent Operator that is aware of a potential misalignment about the evaluation of multiple formations might also anticipate this request when preparing its Operation Notice and offer an election that allows each Party to achieve its preferred outcome.

Clause 10.06-General: i) This Clause was introduced in the 2007 document to address the issues associated with use of a well for multiple purposes when P&NG ownership varies. One of the major issues associated with the Operating Procedure since the mid-1990s has been the handling of a well used for multiple purposes-Operations under the Agreement and other activities. The most common example has been the cost equalization when a Party owning a 100% well abandoned in its own deeper rights then proposes to use it for an uphole Completion in the Joint Lands. Parties holding such a well have typically requested a cost equalization for that use, often based on 100% of the costs of a new well to that formation.

Some have challenged the view that there be any cost equalization for that use, but most have accepted that some cost equalization is warranted. They have typically questioned a reimbursement based on a 100% cost allocation based on a notional new well to that formation, though. They have argued that this would provide a subsidization of the deep test, with this especially the case as the difference in depth between the uphole formation and the deep objective decreases. The 100% equalization also does not recognize that many of the identified uphole opportunities would, in fact, be marginal, salvage type operations that would never have been proposed as the primary objective of a new well at the location.

ii) The Parties may wish to consider trying to negotiate a vertical pooling agreement in many circumstances in which this Clause may apply.

Subclause 10.06A: i) A Party can only rely on the consents under this Clause insofar as it is otherwise authorized by the Regulations or other owners of the applicable rights/the well to use the well for an additional purpose.

A Party may not use a Joint Account well for its own purposes in formations not included in the Joint Lands, unless that other use has been authorized by the other Parties. This reflects the principle that a Party should not be able to use Joint Property for its own gain. This Subclause could see a negotiated transfer of an unsuccessful Joint Account well for assumption of the Abandonment responsibility, perhaps contingent on the initial evaluation of the other formation. However, it could also result in a negotiated cost equalization if its value is high to the Party that wishes to acquire it.

There are two outcomes inherent in this Subclause. The first is that the Party that wishes to use the well for its own purposes would have to negotiate this outcome, often through a negotiated cost adjustment. The second is that the provision is structured to encourage a Party with an attractive deep prospect to drill it outside this Agreement and address secondary objectives in the Joint Lands under Subclause C.

ii) This Subclause, Subclause 10.06B and Subparagraph 10.06C(b)(i) contemplate permitted drilling for an additional 15 metres. These references were included to accommodate a logging tool. This incremental depth may change over time because of changes to technology or the Regulations. Insofar as any such change requires some minor incremental depth, Parties are encouraged to administer the 15m qualification accordingly.

iii) There may be concerns about the integrity of the wellbore or a prospective formation if the additional activities proceed. Any such negotiation should address cost allocation issues, production priorities, any royalty holiday issues and indemnification and liability.

Subclause 10.06B: i) Although this Subclause is presented before Subclause C, it has been structured so that Subclause B is unlikely to be used often. The consent mechanisms and cost allocation in the Subclause are designed to encourage a Party with an attractive deep play to negotiate with the other Parties in advance or proceed under Subclause C. Subclause B creates negative outcomes for a Party that misrepresents a dual use well as only a shallow well in the Joint Lands. The consent of the other Participating Parties is also required for other activities in an Independent Well. In effect, it is a Joint Account well between them.

ii) Prior notice of that additional use must be provided to the Non-Participating Parties, so that they can protect their rights. This would not necessarily require disclosure of confidential information. If, for example, the Joint Lands comprised rights to the base of the R formation, it would be sufficient for the Participating Parties to notify them that they plan to deepen the well below the R formation.

iii) The other major restriction in this Subclause (Paragraph (b)) is the general prohibition on using the well for another purpose if productivity is established in any formation of the Joint Lands. That Paragraph will be relevant any time that Paragraph (d) may apply. It is based on two principles-that production from the Joint Lands has the highest priority and the need to protect the integrity of the wellbore and the formation. The Non-Participating Parties might waive that outcome, probably through negotiation of an agreement that addresses such matters as protections respecting production priorities, cost allocation methodologies, any royalty holiday issues and a clear assumption of responsibility for damage to the well and prospective formations. This obligation may be inconvenient for the Participating Parties because of the inherent requirement to disclose some well information before the Non-Participating Parties are entitled to it. This would have to be assessed against the corresponding benefits.

iv) If the restriction in Paragraph (b) does not apply, the Participating Parties may use the well for another purpose without the Non-Participating Parties' consent. There is an immediate financial consequence if they use this discretion, though. Paragraph (c) provides that the Drilling Costs and Completion Costs included in the Paragraph 10.07A(e) cost recovery will be reduced on the same basis as in Subclause C. Any Clause 10.07 cost recovery for the Joint Lands would be reduced significantly, where this does not depend on a successful Completion in the other formation. This should be considered carefully by a Participating Party that is requested to consent to the use of an Independent Well for another purpose.

v) Paragraph (d) provides that a cost recovery for an Independent Well is waived entirely if it is placed on production (other than for test purposes) in a formation other than the Joint Lands for more than 30 total days unless both portions of the well will be produced simultaneously or the Parties otherwise agree. This authority is not as broad as it first appears, though, as issues associated with the dual use would need to be addressed as part of the consent dialogue required under Paragraph B(b) for additional activities in a productive Independent Well. The last portion of the Subclause addresses the Operator's general duties about measuring production and a reasonable cost allocation in the dual producer situation, where the generic reference is similar to some of the cost allocation provisions in the PASC Accounting Procedure. (This would apply mostly to Operating Costs and Equipping Costs, as Drilling Costs are subject to the cost allocation in Subclause C.) Some fixed costs may be allocated equally to the producing horizons, for example, while variable costs might be apportioned based on total recovered volumes (including water).

vi) The indemnification and liability provisions of Clause 10.18 apply, *mutatis mutandis*. This is subject to the qualification that the Clause does not see Extraordinary Damages excluded on the basis prescribed by Clause 4.04. The normal legal rules on damages apply in this particular instance because the relationship between the Parties and the owner of the other interval is treated as a relationship with a third party. (See also Subclause D.)

vii) It would be prudent for Parties to supplement this provision at the time the provision applies with documentation that addresses their specific expectations. This is particularly important if the cost recovery is attained and the well is producing from both ownership intervals. What, for example, are the rights of one ownership group to conduct further work in the well when the well is still productive in the other interval?

Subclause 10.06C: i) The most common application of this Subclause would be where the Joint Lands are shallower than a deep objective held outside of the Agreement. However, it accommodates the possibility that the Joint Lands may comprise the deeper rights.

ii) The Proposing Party must identify the multiple use issue to the Receiving Parties in its Operation Notice. The detailed processes in the Subclause are designed for the situation in which the Proposing Party intends to use the well exclusively for the evaluation and exploitation of the Joint Lands. That information would supplement the information required to be provided in the Operation Notice for such matters as the description, location, timing and cost of the proposed Operation.

As of the 2015 document, the proposed importation of a wellbore is subject to the consent of the Receiving Parties if the proposed use will begin more than 48 months after the initial drilling rig release date of that well. This reflects the increased risk inherent in using an older well, particularly if it has already been used for other producing activities. There will be circumstances in which the Parties may prefer to modify that period.

A Proposing Party that intends to use the well to produce from both the Joint Lands and other formations (i.e., a dual producer) will need to negotiate the basis for that arrangement with the other Parties, as it is beyond the scope of this Subclause. While they may choose to use the provisions of this Subclause as a platform for their negotiations, they would probably also want to address such additional matters as production priorities, other cost allocation issues, any royalty holiday issues and liability and indemnification issues. (See also Subclause F.)

Some companies have attempted to avoid addressing this issue by ignoring in their Operation Notice the fact that the well was initially drilled to evaluate formations not included in the Joint Lands. The Clause creates negative outcomes for a Party that misrepresents its well.

iii) One might try to structure the cost allocation in Paragraph (b) to prescribe specific methods to allocate the actual intangible and tangible Drilling Costs between the respective portions of the well. The intangible costs, for example, might be allocated on the basis of the number of drilling days for the respective portions of the well (excluding days for formation specific testing). (See "Allocation of Well Costs Between Zones With Different Ownership" by Carlos J. Salazar in the March/April 1991 edition of the AAPL Landmen for an overview of these types of cost allocations.) This Subclause uses a more general approach similar to that used in Clause 10.05. While less prescriptive than that noted above, the reference to the dispute resolution Article should mitigate the risk that this approach would lead to prolonged negotiations.

iv) Subparagraph (b)(i) requires the Proposing Party to provide a reasonably detailed, *bona fide* estimate of Drilling Costs from surface to 15m below the deepest target formation in the Joint Lands, with an exception if the Joint Lands are deeper than the original target. Drilling Costs serving both portions of the well are then reduced by 50%, 75% or 90% under Subparagraph (b)(ii), depending on when the Operation Notice is served relative to the original drilling rig release of the well. The 75% reduction applies after 72 months, and a 90% reduction applies after 180 months. The Parties will sometimes negotiate different percentages when they initially prepare the Agreement or at the time the provision applies, having regard to the circumstances and the ongoing relationship between the Parties.

The problems with use of a 100% cost equalization are clear in an example in which: (a) A drills a $2MM well that is not successful in its 100% T formation; (b) it then proposes an uphole completion in the jointly held S formation 150m shallower; and (c) the Drilling Costs for a new well to the S formation would be $1.9MM. A 100% cost equalization would, in effect, potentially provide A with an evaluation of its primary objective of the T formation for an incremental $100K of gross Drilling Costs, plus the formation specific testing costs.

The 50% reduction was recommended in the AAPL article above, and has typically been used in negotiated resolutions of this issue. The linkage of the percentage reduction to the rig release date reflects the increased risks for well integrity and environmental concerns over time. A different threshold might be negotiated at the time, particularly if more than one formation of the Joint Lands will be tested.

v) The Subparagraph (b)(ii) adjustment only applies to costs serving both portions of the well. Suppose that it was originally drilled to evaluate the shallow 100% D formation and the Proposing Party now wants to Deepen it to the jointly held J formation. The adjustment would only be for the costs from surface to just below the D formation. The Drilling Costs between that depth and the J formation would not be subject to the equalization process, as the Drilling Costs are an integral part of the proposed Deepening Operation to evaluate the J formation. (See Subparagraph (b)(iv).)

vi) Paragraph (c) enables the Receiving Parties to defer their election until receipt of the drilling information for the interval to which the cost equalization pertains, insofar as that information is not already in the public domain. This is a major benefit to the Receiving Parties, as it can alter their assessment of the risk of the Operation significantly. It is also inconsistent with the manner in which information is handled under Clause 10.08.

Access to the information was included to mitigate the risk that the primary motivation for an Operation in the Joint Lands is a cash reimbursement to offset some of the costs associated with the unsuccessful evaluation of the primary objective, rather than the exploitation of the Joint Lands.

A Party drilling a well to which this Subclause may apply needs to be aware of the obligation to provide this information if there are other owners in the well that are not Parties. The entire arrangement is ultimately a negotiation outside the scope of the Agreement if it cannot comply with the requirements in the Clause or it is unwilling to comply with them.

vii) The Receiving Parties are deemed to agree to the proposed Subparagraph (b)(i) calculation, unless a Party objects, by notice. A Party must typically serve any such objection within 10 Business Days after receipt of the Operation Notice (five Business Days if a Paragraph 10.02B(c) seven-Business Day election applies because a rig is then on location for prior work). Any such notice must include in reasonable detail the basis for the objection and a proposed alternative. The allocation under Subparagraph (b)(i) (but not the (b)(ii) percentage reduction) can be referred to Article 21.00 for resolution if the Parties are unable to agree.

viii) The seven Business Day response under Paragraph 10.02B(c) may seem long when the rig is already on location. This is designed to reinforce to the Proposing Party the potential benefit of alerting the other Parties to a potential Subclause 10.06C Operation when the well is being drilled.

ix) Most of the wells to which this Subclause applies will be new wells, where the well is unsuccessful in the deeper rights. The Subclause might also apply to an existing well with an existing wellhead and surface installations. Paragraph (d) addresses that equipment. It basically sees the net salvage value of that equipment used as the equalization value, as calculated under the Accounting Procedure. This amount would be included in Operating Costs under Paragraph 10.07A(b) if a Clause 10.07 cost recovery applied to the well after receipt of the elections from the Receiving Parties.

x) Subclause 10.06D addresses the representations being made by the Proposing Party with respect to the well and the Receiving Parties' rights to review the well file and to visit the well site.

Subclause 10.06D: i) A Party makes minimal representations about a well it proposes to use for the Joint Lands under Subclause C. Paragraphs (a), (b) and (c) are an abbreviated form of the typical "Compliance with Agreements", "Lawsuits and Claims" and "Title" type representations used under sale agreements. Paragraphs (d) and (e) are largely based on the Transferor's "Condition of Wells" and "Environmental Matters" representations in the CAPL Property Transfer Procedure. The latter basically provides that there is no outstanding notice issued under the Regulations pertaining to HSE, where a Proposing Party could not make this representation if there were outstanding work required to satisfy a directive issued under the Regulations.

ii) A Party assessing participation needs to be comfortable acquiring the associated share of Environmental Liabilities for the applicable well. It should review the well file and possibly visit the wellsite to assess the well's condition and its suitability for use.

iii) A Party that determines that the representations are inaccurate would probably try to obtain injunctive relief through the Courts if the concern was significant and it was apparent that discussions with the Proposing Party were not going to allow the issue to be resolved.

iv) Parties will often prefer to supplement this Clause with their own conveyance agreement. This would address the Proposing Party's representations or the expectations for conveyance documentation in more detail, as well as address such other items as any applicable GST. They remain free to supplement these provisions in their Agreements or on a customized basis at the time in the context of their situation.

Subclause 10.06E: The ownership interests in the well and the ultimate responsibility for Abandonment should be negotiated if the well will be produced concurrently from both portions of the well. Otherwise, the ownership of the well and the Abandonment obligations will generally be shared by the Participating Parties. This general rule is subject to two qualifications. The first is that the Proposing Party was to assume responsibility for Abandoning that portion of the wellbore that is of no relevance to the proposed Operation (i.e., rights below the uphole formation of the Joint Lands in which the well is being Completed). The second is for the situation in which the wellbore is to be Abandoned within six months after expiry of the response period to the Operation Notice. Abandonment costs in that case would be allocated to the respective portions of the well, with additional costs resulting from the Operation in the Joint Lands borne by the Participating Parties. This outcome is similar to the approach in Clause 9.04.

Subclause 10.06F: i) Parties will often have the opportunity to acquire another well to be used to exploit formations included in the Joint Lands. The foundation of this Subclause is that a Party that acquires such a well from one or more third parties on a *bona fide* basis will allow the other Parties to participate in that acquisition on an "at cost" basis as part of the proposed Operation. This requires the acquiring Party to identify the basis for the acquisition in its Operation Notice for that Operation and for any Party participating in that acquisition to assume its Participating Interest share of the corresponding rights and obligations associated with that acquisition. The Subclause is structured on the premise that a Party will initiate the process in an Operation Notice. However, the preferred approach would be to discuss any such acquisition in its early stages, so that the Parties could collectively determine the best way to conduct their environmental and technical due diligence for the well.

As of the 2015 document, the proposed importation of a wellbore is subject to the consent of the Receiving Parties if the proposed acquisition will be more than 48 months after the initial drilling rig release date of that well. This reflects the increased risk inherent in using an older well, particularly if it has already been used for other producing activities. There will be circumstances in which the Parties may prefer to modify that period.

ii) A Receiving Party may also acquire a Working Interest in the well indirectly through the cost recovery process. The consideration paid for the well (as calculated on a 100% ownership) will be included as Drilling Costs of an Independent Well for the purpose of the Subclause 10.07A cost recovery if there is at least one Non-Participating Party respecting the associated Operation Notice. In practice, though, many of these wells would be acquired for just $1 and the assumption of the Abandonment responsibility.

iii) An allocation mechanism like that in the Clause 24.01 ROFR process applies if the well is acquired in a large deal or on a non-cash basis. The application of the valuation methodologies from Subparagraphs 10.06C(b)(i) and (ii) may initially seem attractive. There may be circumstances in which that approach may offer a reasonable proxy for value. However, there will be many other circumstances in which the context is that the real cost was the assumption of the Abandonment liability for the existing well. In other words, the direct linkage to those Subparagraphs would often overstate significantly the consideration for the acquisition of the wellbore and invite gaming in the presentation of the proposed allocation.

Subclause 10.07A: i) The first sentence was qualified as of the 2015 document to address the possibility that the Parties have included special provisions in the Agreement to address Multiple Well Drilling Programs, Multiple Well Completion Programs and the development of a Well Pad.

ii) Note the reference to the Independent Well and the cost recovery applicable to it. Suppose that the drilling program was not conducted in accordance with the Operation Notice. Would the cost recovery apply?

An Operation may differ from that described in an Operation Notice in cost, timing, location and depth, and the differences may be material or of little consequence. The answer, then, would depend on the type and degree of the deviation. Immaterial differences in timing or costs are unlikely to affect a cost recovery because they depend on external factors. Similarly, a material difference in costs would probably not have any effect if the original cost estimate had been reasonable and the Participating Parties had no reason to revise it prior to Commencement. If, however, they have (or should have) knowledge of developments that would materially alter the costs or timing, the validity of the Operation Notice might be jeopardized <u>if</u> those changes might have influenced the Non-Participating Parties to participate, particularly if they were highly reliant on the Operator's specialized expertise. Similar considerations apply to such technical factors as location and depth.

If the Operation is, in essence, a different Operation from that proposed, there may be a legal duty on the Participating Parties to advise the Non-Participating Parties of the change promptly and to allow them to re-elect to participate, even if it has already Commenced. This would put the Parties in the same position they would have been in if the revised Operation were proposed initially. This also has implications for the obligations to the other Participating Parties, particularly if a cost recovery were not effective. (This is also relevant to Joint Operations. See the <u>Passburg</u> and <u>Prairie Pacific</u> cases referenced in the annotations on the AFE definition.) Subclauses 3.01E and 10.02H address this issue to some degree.

iii) Suppose a well has been proposed as a well to "test the Y formation" and well information indicates that it is actually only prospective in the shallower R formation, where the Joint Lands include all rights. Would a Non-Participating Party have the right to request the opportunity to participate in the R Completion because the Operation is different from the "Y test"? Is the answer different if the well had been proposed to evaluate the "Y formation and all other formations of the Joint Lands indicated to be prospective during the Operation"? Subject to the Clause 10.05 divided status scenario, the latter phrase is arguably inherent in any drilling activity for the Joint Lands, as wells frequently provide unexpected information. The essence of a drilling Operation to the Y formation is that it will drill through other shallower formations that may be held jointly. While a parenthetical reference has been included in Subclause A of the post-1990 documents, the previous versions are consistent with the outcome that the Participating Parties may use the original wellbore to exploit other penetrated formations of the Joint Lands.

The suggestion that a Non-Participating Party have the opportunity to participate in an uphole Completion without consequence is inconsistent with the risk-reward principle. It would be making an election on the basis of risk that has been adjusted by the Participating Parties' Operation. In addition, previous versions of the document would have included an equalization for the relevant Drilling Costs if this had been the intention. Subclause 10.08B of the post-1990 documents includes one qualification for the situation in which a Party that participated in the drilling and setting of production casing then elects not to participate in the Completion program. It has the right to participate in any subsequent Recompletion in another formation.

iv) A critical element of the mechanism that is not always apparent to users is that the cost recovery only affects the allocation of production from that well. It is helpful to think of a cost recovery as a non-recourse financing arrangement whereby the Non-Participating Party forgoes its share of production until recovery of the prescribed cost recovery from the well. It does not alter the Parties' Working Interests in the associated Joint Lands. A Non-Participating Party can participate in (or even propose) other wells on the same section. This could be another well to exploit formations in which the well has not been Completed or Recompleted if permitted under the Regulations. It could also be an additional well drilled to the productive formation under any increased drilling density permitted under the Regulations.

v) Another key element of the mechanism is that the calculation is generally done on a gross (100%) basis. There is no attempt to prorate Drilling Costs, for example, to a Non-Participating Party's Working Interest share. This is because of the potential for calculation errors in prorating each revenue and cost element to a Non-Participating Party. There are, though, some potential elements of the calculation that require special treatment (i.e., impact of Paragraph 10.05C(b) reimbursement, a Subclause 10.07F encumbrance and linking (on a 100% basis) proceeds and Facility Fees to incremental cost recovery volumes). The calculation is not affected by any cash payment made under Subclause 10.13E.

vi) The objective of the cost recovery is to provide an appropriate reward for assumed risk. The reward is ultimately only as good as the well's productivity. A cost recovery does not reward failure.

vii) Note the reference "that are paid" in Paragraph A(a). "Phantom royalties" cannot be charged during a royalty holiday.

viii) The 1974 and 1981 documents were silent on product enhancement costs for handling production. They did not actually fall within the scope of the formula, as they were not "operating costs" as then defined. In practice, personnel administering penalty accounts intuitively recognized that they should be included in the cost recovery, as those costs were incurred to enhance the value of the production. They generally addressed their recovery through a broad interpretation of "operating costs" or by calculating production proceeds at the wellhead. The 1990 document used the latter approach. The 2007 document introduced the Facility Fees concept. This basically grosses up the Facility Fees applicable to the incremental volumes to 100%. This links the Facility Fees directly to the costs to handle the volumes otherwise applicable to the Non-Participating Party's Working Interest, and gives the same result as if all costs and revenues were prorated to the Non-Participating Party's interest.

ix) The 200% cost recovery for Equipping Costs was introduced in the 1990 document. (The 1974 document allowed for their recovery on an "at cost" basis, and the 1981 document included an interest mechanism.) The 200% recovery was included for two reasons-to recognize there was no certainty that the Equipping Costs would be recovered and to simplify the calculation.

x) Parties typically use different percentages for the Development and Exploratory costs in Paragraph A(e) to reflect presumptions about risk differentials. While users have typically used 300% and 500% for most operating areas, the percentages should be assessed for each transaction.

xi) The definition of Completion Costs includes the cost of any Recompletion or Reworking.

xii) The calculation applies against the wellbore. Suppose a well is not productive in the deep X formation, but it is Completed in an uphole formation (J). The cost recovery is based on the *bona fide* costs that were incurred in the well as a whole, even though the costs incurred below the J formation had no direct bearing on its exploitation. There is an exception to this general outcome when Clauses 10.07 and 10.10 apply to different portions of the well. As the Non-Participating Parties are already potentially subject to a forfeiture of their entire interest in the deeper formations, the costs associated with those deeper formations are excluded from Paragraph A(e) under Subclause 10.10F.

xiii) The traditional cost recovery poses many challenges in practice. These include: (a) the differences in cost (e.g., Facility Fees) and revenue profiles of the Participating Parties; (b) the low priority given to monitoring "payout" type accounts by both Participating Parties and Non-Participating Parties; (c) continuity issues with property sales; and (d) the complexity of calculations for gas properties. It was not feasible to include a volume based reward as an alternative (as in the CAPL Farmout & Royalty Procedure), given the difficulty in predicting the type of activities that could be conducted over the life of the Operating Procedure. It may be attractive, though, to consider other negotiated alternatives in the context of a particular Operation Notice. In addition to the more traditional alternative of a farmout (possibly for a non-convertible ORR), it may be attractive to negotiate a volume based reward as a proxy for value before the well is Commenced or after it is determined to be successful, using the well data. The negotiation of some type of forced farmout penalty for at least some initial period (specified time or Exploratory Wells meeting certain criteria) may also be mutually attractive when negotiating an Agreement for a high-risk, high-reward area in which the initial drilling information could validate the basin model. (See the miscellaneous annotations on high-risk, high-reward properties in the Addendum at the end of the document.)

Another option that may sometimes be attractive is to negotiate a cash buyback of a Working Interest in the well shortly after the well is drilled. This idea is based on the cash premium mechanism that has been traditionally used in international agreements, such as the AIPN and UK model Operating Procedures. This would see a Non-Participating Party buy its way out of the cash recovery situation by paying an agreed upon negotiated amount that makes mutual sense, with any such payment generally regarded as "COGPE" for tax purposes insofar as it does not pertain to tangibles. Any such negotiated amount would probably be less than the full cost recovery amount, to reflect the benefit to the Participating Parties of obtaining funds immediately on a favourable tax basis. The Participating Parties would share any such payment on the basis prescribed by Clause 10.17.

There are several reasons why this might be mutually attractive in a particular case. Having common equity interests early in the development cycle can facilitate pool development, particularly if there are strategic issues with use of regional facilities. A Non-Participating Party could limit the financial impact of the cost recovery if significant Equipping Costs and Production Facilities are anticipated, and it may also be attractive to it if the strategic benefits of being able to book the production and reserves outweigh the cash premium required to reinstate its interest in the well. At the same time, Participating Parties can benefit from a near term receipt of funds (versus receiving production proceeds over time on a less favourable tax basis) and from another Party's participation in the lower rate of return Equipping and Production Facilities. Payment also shifts the entire risk for well performance on the interest from the Participating Parties to a Non-Participating Party buying back its participation.

xiv) Note the deeming mechanism on sale proceeds in the first sentence of the last paragraph. That sentence generally creates a floor price of a Market Price. It is designed primarily to protect Non-Participating Parties against notional allocations of the least attractive gas sales contracts in a Participating Party's portfolio to wells subject to a cost recovery. This is of particular concern if gas prices are volatile and companies have entered into unfavourable hedging arrangements. The outcome is not entirely clear if that sentence was not included, but the <u>Mesa</u> case noted in the annotations on Clause 1.05 might provide some protection from a Participating Party's attempt to allocate volumes on an arbitrary basis from an Independent Well to its least attractive sales contracts. The use of the Market Price for 100% of proceeds gives the same result as using it only for the incremental cost recovery volumes applicable to the Non-Participating Party's interest and prorating all costs to that interest.

A pre-existing dedicated lands reserves-based contract complicates the calculation. If the Non-Participating Party's cost recovery volumes must be sold under that agreement, the proviso basically grosses up the proceeds applicable to the incremental cost recovery volumes to 100%. This reflects the 100% nature of the calculation, but gives the same result as if all costs and revenues were prorated to the Non-Participating Party's interest. Those contracts tend to apply only to older properties, where all owners are typically subject to the same or parallel gas sales contracts.

xv) Audits and other financial adjustments reduce the principal amount on which the multiples in Paragraphs 10.07A(d) and (e) are based.

Subclause 10.07B: i) Suppose that a well drilled under Clause 10.05 was successfully Completed in both the Development Well and Exploratory Well portion, but could not be produced simultaneously and that the Drilling and Completion Costs of the well were borne as follows: (a) Development Well Portion ($2MM): A 50% ($1MM), B 50% ($1MM) and C-0; and (b) Exploratory Well Portion ($2MM): A 100% ($2MM), B-0 and C-0.

Between A and C, the Paragraph A(e) cost base would be $4MM, as any reimbursement to the Development Well participants (100%) under Paragraph 10.05C(b) has no impact on C. Between A and B, it would be $2MM at the prescribed multiple plus $2MM without a multiple because of the participation in the Development Well portion. Any reimbursement to the Development Well participants because A exercised its pre-emptive production right for the deeper portion of the well was treated as a 100% Operating Cost between only A and B in pre-2007 versions of the document.

The modified handling introduced in the 2007 document continued to see the reimbursement handled in the cost recovery on a 100% basis without the multiple. It was included under Paragraph 10.07A(e) to address the situation in which the well is Abandoned in the deep rights in order to conduct an uphole Completion in a formation to which the reimbursement pertains. The modified handling sees the reimbursed costs being recovered after the Paragraph 10.07A(e) costs pertaining to the Exploratory Well, rather than before any recovery of the costs of the exploratory portion of the well as in the 1990 document. (The last paragraph of Subclause 10.07A applies proceeds to Operating Costs before the Paragraph 10.07A(e) costs.) Any outstanding Paragraph 10.07A(e) costs relating to the Exploratory Well portion of the well are waived relative to the former Participating Parties in the Development Well portion of the well if the well is subsequently Abandoned for an uphole Completion in the original Development Well.

ii) The Participating Parties will sometimes Abandon the Exploratory Well prior to the prescribed cost recovery to conduct a Completion or Recompletion in one or more formations of the Development Well portion of the well to which the reimbursement pertained. The former Participating Parties in only the Development Well portion of the well that are subject to the cost recovery have the right to receive an Operation Notice for this proposed Operation. Participation by any such former Participating Party is contingent on reimbursement of: (a) the outstanding amount of the reimbursement applicable to its Working Interest; and (b) the outstanding Equipping Costs applicable to its Working Interest, without the 200% multiple prescribed by Paragraph 10.07A(d). The elimination of the multiple on the Equipping Costs reflects the fact that the Exploratory Well Participating Parties have already had the opportunity to apply production proceeds against 200% of the Equipping Costs. A former Participating Party in the Development Well portion that chooses not to participate in the new work will see the additional costs added to the cost recovery calculation.

To illustrate using the example in annotation (i) above, assume that the Exploratory Well portion of the well is plugged back for a Completion in the original Development Well portion of the well before full recovery of the deep costs. C would remain subject to the cost recovery on the total amount then outstanding. B, on the other hand, would have the option to participate in the Completion by reimbursing the $1MM that had previously been reimbursed to it. B's reimbursement would be smaller if the work were proposed after full recovery of the deep costs multiple and some recovery of the 100% amount to be recovered for the reimbursed amount applicable to the Development Well portion of the well.

iii) The special participation rights in this Subclause only apply if the well is only being retained for activities in the original Development Well portion of the well. They do not apply if the Participating Parties later Complete the well in each portion as a dual producer.

Subclause 10.07C: The election after a cost recovery was introduced in the 1981 document. The 1971 and 1974 documents provided that the Non-Participating Party's acquisition of participation in the well occurred automatically. It would generally acquire the interest if it believed that the benefit of reacquiring its share of production was greater than the potential Abandonment costs or accrued Environmental Liabilities.

Subclause 10.07E: i) For the post-1990 documents, a Non-Participating Party that chooses not to accept participation in the well is basically forgoing its rights in the well and the production associated with its Working Interest through the well from the formations in which that well is then Completed or Recompleted. It otherwise retains its Working Interest in the Joint Lands included in the Spacing Unit of that well, such that it has the right to participate in any additional well on the original Spacing Unit. This would include a well drilled to a different formation or a well drilled under a holding or a reduced spacing order. This is similar to the handling of an Abandoning Party's interest under Subclause 12.02A.

ii) This might be shown on a land information system by setting up the wellbore as a separate ownership split.

iii) The last sentence was added as of the 2015 document to provide the former Non-Participating Party that elected not to accept participation in the well residual rights if other Operations, such as a plugging back and uphole Recompletion or the addition of a Horizontal Leg, were later conducted in the well. This change was made to be consistent with the handling of a comparable situation introduced in Clause 12.03 in the 2007 document with respect to Parties that had assigned their interest in a well in response to an Abandonment notice.

Subclause 10.07F: i) This Subclause was introduced in the 1990 document. It only applies to those encumbrances not borne for the Joint Account that flow with the interest under Clause 15.02. It will not apply to the typical Clause 15.01 encumbrance, such that the issue would have to be resolved by the Non-Participating Party and the encumbrance holder wherever Clause 15.02 does not apply. However, a Non-Participating Party might also consider trying to negotiate the application of these principles to its Clause 15.01 burden for a particular Independent Well.

ii) Suppose that the Operating Procedure is attached to a farmout agreement under which A and B farmed out to C and D and that A has elected to be in a non-convertible 15% ORR under the Agreement. Assume that the interests are: A-ORR (as calculated on 50% of production - net 7.5%); B-25% (farmor that converted its ORR at payout); C-37.5% (25% subject to A's ORR); and D-37.5% (25% subject to A's ORR). If B proposes a well, C elects to participate for only its Working Interest and D elects not to participate, how is A's ORR handled under Clause 10.07?

A's ORR was not an encumbrance borne for the Joint Account, such that the 1981 provision clearly stated that it had no impact. This would be of concern to both A and D, as D is required to pay an ORR on the production respecting the interest acquired from A. This Subclause creates a different result for encumbrances to which Clause 15.02 applies. They will be taken into account under Paragraph 10.07A(a) for only the affected Non-Participating Party. Subclause F provides that 150% of the amount so paid by B on D's behalf is added to the amount recovered thereunder. The 50% premium is designed to compensate the Participating Parties for the delay of penalty payout caused as a result of its inclusion.

iii) Suppose that B did not participate in a well proposed by C when the interests in the above example applied. While C's Working Interest was encumbered by a Clause 15.02 encumbrance, B's did not have any such burden attached to it. Payments made by C on D's behalf would continue to be taken into account for D, but would have no impact on B. Similarly, payments made by C for its own account would have no impact on B.

Subclause 10.07G: Incentives accruing under the Regulations do not affect the calculation under Subclause 10.07A, whether they accrue collectively to the participants in the Operation or to any individual Participating Party because of attributes personal to it. However, "phantom royalties" cannot be charged under Paragraph 10.07A(a) during a royalty holiday.

Subclause 10.07H: i) Disclosure of information for consideration under Clause 18.03 requires the consent of all Parties with a proprietary interest in it. That Clause states that a Non-Participating Party does not have a proprietary interest in the information, such that its consent is not required.

ii) A disclosure of well information will typically be in exchange for other well information, rather than cash. Any cash contribution received by the Participating Parties for disclosure of well information under Clause 18.03 will be applied against the amount in A(e) to reduce the penalty cost base.

Subclause 10.08A: i) Except as provided in this Subclause, a Party may not issue an Operation Notice for other Operations in a well that is capable of production in Paying Quantities without the authorization of the other Parties holding a Participating Interest in the well (on such terms as they may agree). The restrictions are designed to ensure that cash flow will not be compromised by a new Operation that may not be successful or that may damage the wellbore or the productive formation.

The 2007 document was qualified so that a Party may issue an Operation Notice for a well if it has not been Completed within 36 months of its drilling rig release or it had produced (other than for test purposes) and has then been Suspended for at least 24 consecutive months. This was designed to facilitate activity with respect to inactive wells without going so far as to deem the well not to be productive and potentially invite lease retention issues.

The authorization in the last sentence does not extend to a Completed well that has not yet been produced, to recognize that infrastructure limitations may restrict the ability to put a good well on production. It does not follow from this, though, that the restriction in Paragraph (a) will necessarily apply to that well, a Completed well or a well that has produced in the preceding 24 months, as the Paying Quantities test is a question of fact in each case.

ii) A Party that wishes to conduct such an Operation in a productive well would need to negotiate mutually acceptable outcomes with the other Parties for such matters as production priorities, any cost allocation/penalty issues, damage to the well or formation and any royalty holiday issues.

Similar considerations apply if a Party wishes to convert a well to a horizontal producer by Abandoning a portion of the well and redrilling the formation horizontally. Because a Party may be reluctant to forgo the production and cash flow from the well, the Parties might attempt to negotiate an outcome in which the cost recovery for the horizontal Operation were linked to incremental production. This would be structured so that a Non-Participating Party would retain its current level of production from the new Operation, subject to normal decline, while being subject to a cost recovery (perhaps at a negotiated lower multiple) for the remainder of the production associated with its Working Interest.

iii) The Operations contemplated by this Subclause are in the context of formations included in the Joint Lands. Clause 10.06 would apply to the situation in which the contemplated activities pertained to formations not included in the Joint Lands.

Subclause 10.08B: i) A Non-Participating Party generally may not propose or participate in Operations under this Clause during the period in which a cost recovery applies. It does not, for example, typically have the right to participate in the Completion or Equipping of an Independent Well. (See the definition of Receiving Party.)

There are three exceptions to this handling. The first relates to the rights of a Party that participated in only the Development Well portion of a Clause 10.05 divided well, where the well is initially produced from only the Exploratory Well portion of the well. (See Subclause 10.07B) The second is as provided in Subclause 10.08C for participation in a Deepening or Sidetracking proposed to it. The third is for the situation in which a Party had participated in the drilling and setting of production casing, but declined participation in the Completion program.

For the latter, it may participate in a Completion or Recompletion program in a different formation without having to pay, in cash, any outstanding cost recovery under Paragraph 10.07A(e). Although this situation would often arise when the deeper formation is being Abandoned in favour of further Operations uphole, this will not always be the case. It is quite possible that the Participating Parties in the deeper formation will want to conduct further Operations so that the well can be produced from more than one formation simultaneously.

Paragraph (c) accommodates this by providing that the Clause 10.07 cost recovery would continue to apply to the original Completion or Recompletion, notwithstanding the special election granted for the new Operation. Paragraph 10.05C(a) will apply, *mutatis mutandis*, in this circumstance if there were any resultant variance in participation in the well. In essence, that Paragraph clarifies the Operator, includes a measurement obligation and provides some direction about the allocation of Operating Costs. Parties that find themselves in this situation would find it beneficial to supplement this provision with additional documentation that addresses their expectations in their particular fact situation.

Any new participant is required to pay its Working Interest share of the unrecovered principal amount for Equipping Costs for equipment to be used in conjunction with that Operation (with a corresponding adjustment to any existing cost recovery). This is a unique situation, as that Non-Participating Party has participated in all of the Drilling Costs and the costs of production casing that were required to conduct the additional Operation.

ii) This handling of Equipping Costs reflects the dual use of the equipment and the fact that this Non-Participating Party has potentially seen its Working Interest share of production proceeds previously applied against the cost recovery.

Subclause 10.08C: i) Prior to the 2007 document, the Operating Procedure had been silent about a Deepening or Sidetracking proposed for a well that was drilled as an Independent Well and subject to the Clause 10.07 cost recovery. (This Subclause could not apply if a Clause 10.10 forfeiture already applies to the well, although the Parties would always be free to negotiate a different outcome at the time.)

Subject to the qualification in annotation (ii) below, a Non-Participating Party's ability to participate in that Operation is probably not contentious. There was no guidance about the election mechanism in pre-2007 versions of the document, though. There were three major potential approaches. A Party could participate if it paid its share of the entire uphole cost of the well. It could participate with no direct responsibility for any uphole costs, as it already contributed a potential cost recovery in support of the well. It might also be required to make a specified partial reimbursement of uphole costs that were not formation specific evaluation costs, such that the costs of any testing program in the uphole formations would be excluded.

Subject to the exclusion of some costs for a Sidetracking, the 100% reimbursement in the first approach is used. This puts that Party in the same position as it would have been in if the well were initially proposed to the different depth. If it elects not to participate in the additional Operation, the costs of the additional Operation will be added to the cost recovery. If it elects to participate and make the reimbursement, it will become an owner in the acquired well on the same basis as if it had originally participated in it. This would see the new participant receive a cash credit for any intervening production applicable to its Working Interest in the acquired well. The new participant would also have a credit or debit for any subsequent adjustment of costs and a share of any other liabilities that had accrued for the Joint Account. Subject to the qualification for the plugged portion of a Sidetracked well, this structure also avoids the complexities in applying a cost recovery to the shallow formations and having different ownership interests in the wellbore. (A Non-Participating Party normally would not have rights or obligations for the wellbore until it acquires them after a cost recovery.)

This Subclause is based on three major principles. The first is that a Party that did not participate in the original well is permitted to participate in the new Operation, as it differs materially from that described in the original Operation Notice. The second is that the costs to the depth at which the Operation begins are integral to it and are to be reimbursed. The third is that the costs respecting formations deeper than the depth at which a

Sidetracking commences do not result in a cash reimbursement, as they are, in effect, being incurred a second time to evaluate the same objective at a different location. (One of the consequences of excluding these costs from the cash reimbursement is that any revenues pertaining to the deep formation in the original wellbore are retained by the original Participating Parties, and applied to the original cost recovery. The alternative handling would see both the deeper costs and revenues coming into the reimbursement equation, such that the cost base would typically be materially higher.)

ii) The introduction of Subclause 10.02H in the 2015 document allows the Participating Parties some flexibility to conduct a Sidetracking within a specified radius of the original location. This modification recognizes the real probability that they might Sidetrack a wildcat well because of the information they obtain during the drilling of the well. It is designed to ensure that the Non-Participating Parties do not have the opportunity to re-elect to participate at this stage and avoid the consequence of their initial election after the initial work has changed the risk profile drastically. This flexibility is particularly beneficial in the context of wells being drilled to evaluate a prospect in a complex geologic setting, such as the foothills.

iii) The information about the objective from the original wellbore and the decision to proceed with the Sidetracking would probably impact the assessment of the risk of the Sidetracking. This reinforced the inclusion of a 100% cost reimbursement for the well to the depth at which it begins.

iv) For context, Sidetracking excludes deviations associated with straightening the wellbore, drilling around obstructions and other mechanical difficulties. In effect, it addresses an intentional decision to evaluate a different downhole location than that identified in the original Operation Notice.

v) A Non-Participating Party considering the participation election does not have the right to obtain the information for the well prior to its election, unless it is then entitled to that information under Clause 10.19. However, the disclosure of this information may sometimes occur in practice because the Participating Parties may want to facilitate a participation election and have another Party share the additional costs of the Operation.

vi) A Non-Participating Party that does not make the equalization payment to the Participating Parties by the required time is subject to the potential application of the Clause 5.05 default remedies, subject to an important qualification. The Operator of the Operation (probably in consultation with the other Participating Parties) may serve notice that the participation election is void, in which case the cost recovery would apply. A Non-Participating Party making this election should monitor the reimbursement process to ensure internal compliance with the requirements. In practice, most Parties would probably only exercise their right to void the transaction for non-payment after notifying the Non-Participating Party that payment was late and providing them an opportunity to rectify the default.

vii) A Non-Participating Party considering the participation election should conduct some due diligence to ensure that it would not be assuming unforeseen liabilities because of its retroactive participation in the uphole portion of the well.

viii) A Sidetracking would result in an adjustment of costs under Paragraph 10.07A(e) for a Non-Participating Party that did not participate in it. The costs excluded from the cash reimbursement will be included in the cost recovery, and supplemented by the costs of the Sidetracking and any associated Completion attempt. This is designed to provide an incentive to participate in a Sidetracking, while providing a full recognition of assumed risk relative to a Non-Participating Party that chooses to continue to sit on the sidelines.

Subclause 10.08D: Except as provided in Subclauses 10.07B and 10.08C, the processes in Clause 10.07 will apply, *mutatis mutandis*, to Independent Operations conducted under Clause 10.08. The development or exploratory status will be determined at the time of the Operation, not when the well was originally drilled. Otherwise, a new Operation on an old well could result in an exploratory penalty because of the well's original exploratory status, when the same Operations in a new well at the same location would be categorized as development. This reflects the degree to which subsequent investment decisions can be significantly influenced by other Operations in the vicinity.

Subclause 10.08E: i) This Subclause is similar to Clause 9.04. It was broadened in the 2007 document to apply to an existing well on which an Operation is conducted under either Clause 10.08 or 10.10.

Assume that A, B and C hold Working Interests in the Joint Lands. A and B participated in drilling a well, and Suspended it. A later conducts a re-entry and Completion in which B elected not to participate. A then notifies B within six months of its intention to Abandon the well. After salvage of the equipment placed by it on the well, A turns the well and formation back to A and B for Abandonment and salvage of their joint equipment.

Operations would then be for the Joint Account of A and B in proportion to their respective Participating Interests in the well, subject to three exceptions. Equipment and material added to the well at A's expense would be salvaged for A's sole account. Any additional costs of Abandonment (including Environmental Liabilities) associated with A's Operations would be for only A's account. Similarly, nothing in this Subclause alters the Parties' respective rights and responsibilities for Losses and Liabilities associated with that Operation, such that B would retain all remedies provided to it under Clause 10.18 with respect to A's Operation.

ii) If the Participating Parties in the Clause 10.08 Operation retain that well after that six-month period, they will reimburse the Clause 10.08 Non-Participating Parties their respective shares of the net salvage value of the applicable material and equipment in proportion to their original Participating Interests therein. The reimbursed amounts are treated as Operating Costs under Paragraph 10.07A(b) for any cost recovery that applies.

Subclause 10.08F: i) A Party receiving an Operation Notice for Equipping a well in which it holds a Working Interest has historically had the choice of participating or being subject to a cost recovery on the same basis as is prescribed under Clause 10.07. The 2007 document expanded the options available to it by enabling it to elect to take in kind its share of the Petroleum Substances otherwise being served by the Equipping if the nature of the Equipping Operation allows a Party to take its production in kind without using the assets included in the Equipping. This allows it to install a "splitter" at the well site, so that it can manage its volumes differently than contemplated by the Equipping.

A Party making this election will generally be solely responsible for the costs of any additional equipment required to handle or measure its share of production. The one exception to that handling is the situation in which the proposed Equipping pertains to the installation of equipment that serves substantially the same function as equipment already on the well (e.g., another pipeline to a different location when there is an existing line in place). The Participating Parties in the proposed Equipping will be responsible for the incremental costs for the splitter and measurement in that situation, and may not include these costs in a cost recovery relative to any Parties that elected to be subject to the cost recovery under Paragraph 10.08F(c).

Paragraph 10.08F(b) and the last paragraph of Subclause 10.08F were modified as of the 2015 document to address a deficiency in the 2007 Subclause. The Regulations in Alberta require all production from a gas well to flow through a single separator and associated metering equipment for measurement purposes. A Party that would prefer to route its production in a different way than contemplated by the Equipping notice would be unable to take in kind without using a separator and metering equipment that was included in the Operation Notice for an Equipping.

As of the 2015 document, a Receiving Party facing this situation has the right to elect to participate in the component of the proposed Equipping that is a requirement under the Regulations and to take in kind without using the remaining equipment within the scope of the proposed Equipping. In essence, this sees a *mutatis mutandis* application of the Subclause, such that it would be able to participate in the segment of the Operation that is required under the Regulations and to avoid the downstream component of the Equipping Operation. It is a precondition to the ability to take in kind in that circumstance that the Party will have participated in the installation of the equipment required by the Regulations.

A Party faced with this situation under the 2007 document would attempt to negotiate this type of outcome with the Operator. An Operator faced with this situation should be aware that it potentially falls within the scope of Subclause 1.04B relating to conflicts between the Agreement and the Regulations and the potential use of severance. That Subclause states that the applicable provision would be "severed from the Agreement to the extent necessary to resolve a conflict…". Any such severance due to a conflict creates a duty on the Parties to "mutually attempt in good faith to negotiate a replacement provision that will secure the purposes of the original provision in a legally valid manner." Regarding the proposed original Equipping as two discrete segments-the separator and metering and the remainder of the tie-in would appear to meet that test and to allow all Parties to achieve the outcomes contemplated by the Subclause.

ii) There are practical implementation issues associated with the take in kind option for such matters as compensation for shutting in production, surface sharing and liability and indemnification that the Parties should address at the time. Other than for the inclusion of a mutual liability and indemnification obligation, it is not feasible to cover them in this document because of the degree to which these issues are situation dependent.

Another potential implementation issue relates to the situation in which the Operator attempts to frustrate the right of a Party to effect its take in kind election. This would potentially see the application of the Further Assurances provision (Clause 25.01).

iii) A Party that elects to take in kind and then fails to do so will be a Non-Taking Party. It will be subject to twice the marketing fee under Clause 6.04, as well as an additional fee for use of the assets included in the Equipping on the same basis as prescribed by Clause 14.04. This structure is premised on a *bona fide* election and a temporary failure to take in kind. The construction is not intended to enable a Party that has no intention to take in kind to make the Paragraph F(b) election. There may be instances in which the Parties chose to modify the end of the Subclause so that the Participating Parties have the option to terminate the Paragraph F(b) election and replace it with a Paragraph F(c) election if the electing Party fails to begin to take in kind within, for example, 12 months following the completion of the Equipping activity.

iv) The preferred approach may be a negotiated outcome at the time, particularly if taking in kind would significantly impact use of the equipment to which the proposed Equipping pertains. In practice, the impact may be so significant that it may cause the Proposing Party to reconsider the Operation or its perspective on a negotiated resolution.

Subclause 10.09A: i) This Subclause addresses an initial Abandonment, and is similar to Clause 1006 of the pre-2007 documents. Subclauses 10.09B and C apply to wells that are initially Completed successfully, but Abandoned before the cost recovery. The decision is deferred if the initial program under Article 9.00 is the setting of production casing and the Suspension of the well, pending a later Clause 10.08 re-entry and Completion.

ii) The "timely manner" reference is situation dependent. A Non-Participating Party subject to a cost recovery does not share in production from that well. It still retains its Working Interest rights in the Joint Lands to propose another well if the Participating Parties do not proceed to Abandon.

Subclause 10.09B: i) This is similar to Clause 1009 of the 1990 document, but the 2007 document clarified the impact of estimated surface restoration costs in the calculation.

ii) This Subclause does not provide the Non-Participating Parties with any right to take over this well. This would have required the inclusion of a specific cost adjustment process and possibly a second election process. It will sometimes be mutually attractive to provide them with the opportunity to take over the well at the time on a negotiated basis, as the Participating Parties typically regard the well as a liability at that stage.

Subclause 10.09C: i) There is no longer a provision similar to Clause 1015 of the 1990 document whereby the Non-Participating Party "regains" its rights to formations in which an Independent Well is Abandoned. The cost recoveries in Articles 9.00 and 10.00 reward success, not failure. The reward of a cost recovery applies to the share of volumes applicable to the Non-Participating Party's Working Interest that can be produced from the well to which the cost recovery applies, not the Non-Participating Party's Working Interest in the applicable Joint Lands.

ii) A Non-Participating Party may be responsible for its share of Abandonment costs if it participated in drilling the well and the Participating Parties in a subsequent Operation Commence Abandonment of the well within the six-month period prescribed by Clause 9.04 or Subclause 10.08E. A Non-Participating Party only acquires rights in an Independent Well Abandoned hereunder insofar as it is required to assume Abandonment costs.

Clause 10.10 - General: i) The Clause only addresses wells that preserve title. Some forms of tenure allow lands to be maintained because the holder incurred eligible expenditures for geological or geophysical work or well activities to satisfy prescribed annual work requirements. This is relevant if the Joint Lands are in Saskatchewan or British Columbia and they include a permit (or may include a permit under an area of mutual interest). Structuring a suitable provision is more complicated if the interests in the permit lands are not consistent.

ii) The Parties also might be able to obtain an extension to the term of a B.C. lease if they commit to a work program during the following year of the lease. While typically a well, the "committed" work might also be a seismic program and a well that is contingent on the results of that work.

The Parties should consider creating a provision that is customized to their own circumstances, as there is no generally accepted provision on this issue. Subclause 3.10E of the post-1990 documents addresses this topic to some degree if there is any requirement to post a refundable deposit under the Regulations to secure performance of the work. Paragraph 7.01(b) and Subclause 10.03B were also modified in the post-1990 documents to provide greater flexibility for the period within which to Commence this type of Operation. It was not otherwise feasible to try to include a Clause to address this issue because of major philosophic differences about the level of precision that is required for a contemplated Operation in order to trigger a forfeiture by a Party that was unwilling to agree to a "commitment" at the time the representation was required to be made under the Regulations. The biggest item of discussion is likely to be the level of certainty about the Operation that is required to be presented in order to enforce a forfeiture obligation when the specific well location and the associated costs are unlikely to be finalized at that time. Given the credibility impact on the proponent in the eyes of the regulator if the work is not ultimately conducted, are the other Parties subject to an "in or out" election at that time, subject to protections if the scope of the represented work changes materially? Or is the ultimate election deferred until an Operation Notice with a more specific description of the Operation is presented in due course? Any such provision would also need to address the possibility that a Party may prefer to conduct an alternative Operation that would also satisfy the requirement.

iii) The Clause has been structured to address the possibility that title preserving Operations may be conducted for more than one well during the title preserving period. In practice, the vast majority of title preserving scenarios will involve a single title preserving Operation.

Subclause 10.10A: i) A critical criteria when considering if a well is a Title Preserving Well or a Subsequent Title Preserving Well is that the applicable Operation is conducted "hereunder" (i.e., under this Agreement). Assume a Party drills on its 100% lands where the well could retain portions of the Joint Lands. Clause 10.10 does not apply to the well, so that Party must negotiate an agreement with the other Parties if it wishes to obtain any of their interest in the applicable Joint Lands. The corollary of this is that a Title Preserving Well creates a forfeiture requirement for only the Joint Lands, such that there is no impact on other offsetting lands, even if held by the same Parties in the same interests under another JOA.

ii) The Preserved Lands are any Joint Lands that would revert under the relevant Title Document(s) if the Operation were not conducted. There are several subtle points about the provision that were emphasized in the post-1990 documents. Firstly, a well can be a Title Preserving Well for several Title Documents simultaneously. (The determination is on a Title Document by Title Document basis, but the application to multiple Title Documents was clarified.) Secondly, some formations might be continued without the Title Preserving Well, such that a cost recovery would apply to those formations for the well, instead of the forfeiture. Thirdly, the Title Preserving Well does not have to be located on Preserved Lands - a step-out well on continued lands can cause the continuation of offsetting lands. Fourthly, there would only actually be Preserved Lands/Common Preserved Lands if the work, in fact, enabled retention of Joint Lands. (After the licence validation phase (lands retained for activity), a D&A well will generally be of little value because of the need to prove productivity to continue the rights. The one exception to this is for any temporary continuation that may result (e.g., Alberta Section 16 continuation).) Fifthly, lands that may be retained through payment of compensatory royalties fall outside the scope of the provision. The cost recovery mechanisms apply to an Independent Operation that enables the applicable Joint Lands to be retained, and the forfeiture process in Subclause 3.10E applies if compensatory royalties are being paid and a Party chooses not to pay its share.

Last, but certainly not least, the classification of a Title Preserving Well and Preserved Lands are situation dependent. In <u>APL Oil & Gas Ltd.</u> v. <u>Amoco Canada Resources Ltd.</u>, [1993] A.J. No. 1031 (Alta Q.B.), the plaintiff elected not to participate in a well proposed within the title preserving period under the 1974 document. During the response period to the Operation Notice and prior to its election, it asked to make a continuation application for the lands instead of drilling the well. Its intention was to seek continuation using a new offsetting well (8-10 mmcf/d) for which the parties did not have information, where it believed its application would be successful. The other parties did not agree to this request. It elected not to participate in the well, while objecting that it was not, in fact, a title preserving well and a production penalty should apply to its non-participation.

The Operator allowed the plaintiff to present well data for the confidential offsetting well to the Crown prior to expiry of the Title Document, but after expiry of the response period to the Operation Notice. Confirmation of continuation of the lands was received prior to the expiry date and the Spudding of the well. The Court determined on the facts that the well was not a well to preserve title under the 1974 document. (See also <u>Amethyst Petroleums Ltd.</u> v. <u>Primrose Drilling Ventures Ltd.</u>, 2006 CarswellAlta 1023 (Alta. Q.B.), appeal allowed in part [2007] A.J. No. 1242 (Alta. C.A.), appeal dismissed [2008] S.C.C.A. No. 30 (S.C.C.). It found the classification to be a question of fact in the context of a previously challenged offset notice issued by a lessor and the 1990 document. There was also some language in the judgments bringing into question whether a well was actually a well to preserve title if it was being drilled for reasons other than to preserve title. This was notwithstanding that the Clause in each case was entirely focused on outcomes (rather than intention) and that wells are typically drilled to position the Parties to produce Petroleum Substances and generate revenue, not only to retain land. It was also not apparent if the Court in <u>Primrose</u> considered the potential impact of the Waiver Of Relief Clause introduced as Clause 2807 of the 1990 document.)

The document does not include any specific rules about the wells that may or may not be used to demonstrate that Joint Lands would have been retained without the Independent Well. This approach was taken to ensure that the determination would be situation dependent.

iii) Assume that the applicable Title Document is a licence, that a well has validated less than the entire licence and that a Party is considering issuance of an Operation Notice to ensure that its priority lands would be retained after expiry. It should request an early land selection under Subclause 3.10D and then determine if it will issue the Operation Notice after the land selection thereunder.

iv) An interesting application of the Clause is to a non-cross-conveyed pooling in which A's lease has an imminent expiry (90 days) and B's lease does not (24 months). Suppose that B elects not to participate in A's proposed well to avoid the reversion of A's lease. While the well would be a Title Preserving Well, there are no Preserved Lands with respect to B's non-participation. The Clause 10.07 cost recovery would apply to it, as B's rights were not expiring. Why would B ever be worse off than it would be if 100% of the interests were subject to B's lease? However, if the situation were reversed and B proposed the well, A would be subject to the Clause 10.10 penalty, as its interest would satisfy the Preserved Lands test. (The Parties to a non-cross-conveyed pooling also need to be clear if there is any expectation that the Parties in a contributed tract have any pre-emptive election right under Subclause 10.02C to assume the share of costs of a Party in their tract that chooses not to participate in an Operation.) This outcome is clear if one considers other situations in which: (a) the expiring lease represents a very minor portion of the Spacing Unit; (b) the non-expiring lease is continued indefinitely by existing production; or (c) the other Party holds a fee title for which it will issue a lease due to its non-participation.

Similar considerations apply to a Party with a Working Interest in the Spacing Unit under two different Title Documents if only one of those documents had a pending expiry. From a risk-reward perspective, the forfeiture outcome should only apply to that portion of its Working Interest subject to loss under the Title Document. The cost recovery should apply to its remaining Working Interest. The Parties would need to consider any other specific implementation issues in their particular context, and should document those expectations in their Agreement or at the time.

v) A well drilled on lands not subject to expiry may be a Title Preserving Well for other lands. A Subsequent Title Preserving Well can also be a Title Preserving Well, insofar as the Joint Lands (areal and stratigraphic) to be preserved by it do not duplicate those preserved by an earlier Title Preserving Well. A deep Subsequent Title Preserving Well may also continue rights deeper than those preserved by a Title Preserving Well. This was presented more clearly in the post-1990 documents.

vi) Note the reference to Completion, Recompletion or placing a well on production. A Title Preserving Well is not limited to drilling a well, as in the 1974 and 1981 documents. A drilled well, though, is not required to be Completed or Recompleted if retention is a function of activity (e.g., initial term of an Alberta licence).

vii) The Parties select the date by which a Title Preserving Well must be Commenced in the definition of Title Preserving Well. This allows the Parties to consider such factors as surface accessibility and required regulatory approvals in environmentally sensitive areas. This provides the Parties with greater flexibility than had been prescribed by the 1974 (45 days) and 1981 (one year or 1/6 of term) documents. The Parties should generally use 365 days for projects in British Columbia because of operational logistics and the possibility that a lease continuation may be conditional on a drilling "commitment" during the next year of the term.

viii) Some Title Documents (e.g., B.C. drilling licences) provide the grantee with the option to extend the term for an additional one-year period through payment of a higher rental without the grantor's prior approval. The proviso in the definition of Title Preserving Well links the reversion date for such a Title Document to the end of the extension period, as the Parties generally exercise that right in practice.

Subclause 10.10B: i) Subject to the qualifications in Subclauses 10.10C and D, a Non-Participating Party for a Title Preserving Well will forfeit:

(a) 100% of its interest in the well and its Spacing Unit at completion of the Operation, <u>insofar only as they pertain to the Preserved Lands</u> and a <u>Subsequent Title Preserving Well has not then been Commenced whereby that Spacing Unit would be Common Preserved Lands</u>; and

(b) 100% of its Working Interest in the balance of the Preserved Lands at the date they otherwise would have reverted to the grantor of the applicable Title Document, subject to any application of Subclauses 10.10C, D and E.

If certain shallow rights included in the Joint Lands were not included in the Preserved Lands, the cost recovery prescribed by Clause 9.03, 10.07 or 10.08 would continue to apply to the well and its Spacing Unit for those zones. Similarly, the Spacing Unit forfeiture would not initially apply to deep rights not penetrated by the well, although those rights could potentially be captured under Paragraph (b) in due course.

ii) The Participating Parties knew the type of penalty they would receive in the Title Preserving Well Spacing Unit under the 1990 document at the time they conducted the Operation, assuming the well actually preserved lands. The 1981 document provided that a Non-Participating Party only forfeited its interest in that Spacing Unit if it did not participate in a "similar well", such that the Participating Parties did not know the form of penalty for the Spacing Unit at the time they elected to participate in the well. The 2007 document was modified to provide greater flexibility in the Spacing Unit for the Title Preserving Well because of the possibility that a Subsequent Title Preserving Well that also could have retained those lands is Commenced before completion of the Title Preserving Well activity. However, it does not offer the same wait and watch opportunity as under the 1981 document.

iii) The delayed forfeiture in Paragraph B(b) occurs at the date the lands otherwise would have reverted under the applicable Title Document(s). Paragraphs 10.10C(a) and (b) can operate to reduce the interest to be forfeited to the participants in the Title Preserving Well.

iv) A Subsequent Title Preserving Well might be a Title Preserving Well for lands other than the Common Preserved Lands. This Subclause applies, *mutatis mutandis*, between the Parties if that is the case. This was expressed more directly in the post-1990 documents.

Subclause 10.10C: i) The consequences in this Subclause were introduced in the 1990 document. It is very different from the comparable provision in the 1974 and 1981 documents. Those outcomes were not clear until the similar well decision was made, which might not be until after the first well was drilled. The 1990 approach admittedly poses a problem if there is no agreement on the technical merits of a drilling location and simultaneous wells are drilled during the title preserving period, particularly for an unvalidated licence. In that case, it is preferable to negotiate a result appropriate for the situation, and the negative implications of a "race" would typically motivate Parties to do this in practice. While this result would not occur under the earlier documents, the ability to alter the risk thereunder was regarded as a much more serious problem in practice. The modifications to Paragraph 10.10B(a) were included to mitigate some of the problems with the 1990 approach for the Spacing Unit for the initial well.

ii) The following will apply to a Subsequent Title Preserving Well, subject to any revision of Common Preserved Lands under Subclause 10.10D:

(a) a Non-Participating Party for the Title Preserving Well that participates in the Subsequent Title Preserving Well will not be required to forfeit its Working Interest in any Common Preserved Lands under Paragraph B(b). (It could still forfeit an interest, though, in the Spacing Unit for the Title Preserving Well under Paragraph B(a));

(b) insofar as the Spacing Unit for the Subsequent Title Preserving Well is located on Common Preserved Lands that are not part of the Spacing Unit for the Title Preserving Well, a Non-Participating Party in both wells will forfeit its Working Interest in the Spacing Unit of the Subsequent Title Preserving Well to the Participating Parties therein (rather than to the Participating Parties in the Title Preserving Well). Either Paragraph B(b) or Subclause E would apply to its remaining interest in the balance of the lands preserved by the Title Preserving Well; and

(c) a Non-Participating Party for the Subsequent Title Preserving Well that participated in the Title Preserving Well would only be subject to a cost recovery for the Subsequent Title Preserving Well if it was drilled on initial Preserved Lands (or the Joint Lands not subject to the contemplated reversion). If the Subsequent Title Preserving Well was also a Title Preserving Well for other Joint Lands, the Subclause 10.10B forfeiture process would also apply to that Non-Participating Party for the applicable Joint Lands.

Subclause 10.10D: This Subclause was introduced in the 2007 document because the activities associated with the Title Preserving Well or Subsequent Title Preserving Well might only have resulted in a temporary retention of the rights (e.g., Alberta Section 16 continuation). Parties need to revisit the Common Preserved Lands at the end of a temporary retention to determine the activities that caused further continuation of the applicable Common Preserved Lands. In essence, the reward criterion then shifts from a reward for activity to a reward for success. To illustrate the application of this Subclause, consider the situation in which four sections of Alberta Crown leases are expiring in an area in which Cardium oil is the main objective. A has drilled a Title Preserving Well on SE1 (D&A) and B has drilled a Subsequent Title Preserving Well on NW11 (oil), where each was drilling through expiry and would entitle the Parties to a Section 16 continuation of all four sections for about six months. No other well was drilled during the Section 16 continuation period. The Joint Lands could then only be continued based on demonstrated productivity. While A took risk in drilling the Title Preserving Well, the ultimate retention of the lands will be due to B's well in this example. A Party that did not participate in B's well should then forfeit its Working Interest in the Joint Lands continued as a result of that well. This issue was not addressed in any of the previous versions of the document, such that Parties in this situation would need to try to negotiate this type of outcome based on risk-reward principles.

Subclause 10.10E: Paragraphs B(a), C(a) and C(b) include special rules for the Spacing Units for the Title Preserving Well and the Subsequent Title Preserving Well. This provision addresses the forfeiture of a Non-Participating Party's interest in the remainder of the Common Preserved Lands. The forfeited interest is allocated equally to the Title Preserving Well and the applicable Subsequent Title Preserving Well(s). The allocated interest is then apportioned among the Participating Parties in the respective wells under Clause 10.17.

Subclause 10.10F: i) This Subclause addresses Drilling Costs and Completion Costs for the formations subject to the forfeiture if a cost recovery also applies to a different portion of the well. Drilling Costs for the formations deeper than the deepest formation not subject to the Clause 10.10 forfeiture and Completion Costs for forfeited formations may not be included under Paragraph 10.07A(e). Inclusion would provide a second reward (cost recovery, plus forfeiture) to the Participating Parties for that portion of the costs.

ii) Given the potential dual ownership in the well, it is beneficial to supplement the expectations in the Clause if the well will be retained as a dual producer. This would address such matters as the ability to conduct additional Operations in the well if the well is still productive in the other portion.

Subclause 10.10G: This Subclause was introduced as of the 2015 document to clarify what was inherent in the prior versions of Clause 10.10. The title forfeiture process in Clause 10.10 impacts the Parties only with respect to their Working Interests in the affected Joint Lands and any associated Title Preserving Well or Subsequent Title Preserving Well on the basis prescribed by this Clause. Any additional well that had value as an asset would presumably have resulted in the retention of a portion of the Joint Lands. The Parties that receive an assignment of a Party's Working Interest through this Clause do not receive an assignment of any other well that happens to be located on the mineral rights that are the subject of the Clause 10.10 assignment, as there is no language in the Clause respecting other wells and equipment. The forfeiting Parties retain their existing associated share of Environmental Liabilities and Abandonment obligations as a consequence, unless otherwise agreed by the Parties at the time.

Subclause 10.10H: One practical challenge is the determination of the lands that are preserved by a Title Preserving Well, as illustrated by the <u>APL</u> case noted in the annotations on Subclause 10.10A. Ideally, the Parties would attempt to obtain a predetermination from the applicable regulatory agency to ascertain Preserved Lands. However, this determination will probably be achieved through negotiation in many cases because of timing problems or the reluctance of regulatory agencies to make a pre-determination. In practice, the reference to a dispute resolution process will generally only serve as an impetus towards more timely and reasonable negotiations than might otherwise be the case.

Clause 10.11: i) A Party may conduct a geophysical program over the Joint Lands without prior notice. This admittedly conflicts with the underlying policy objective of encouraging Joint Operations, particularly if a program is primarily conducted on the Joint Lands. However, industry experience has been that an exploration program conducted on the Joint Lands is often a portion of a larger regional program or is also intended to evaluate formations that are not held jointly or subject to any area of mutual interest. As of the 2007 document, a Non-Participating Party that wants to obtain a licence or other access to that data would have to negotiate the terms of access with the owners of the data, where they are under no obligation to accept any offer. This Clause had previously provided a Non-Participating Party with a relatively short window to acquire a licenced copy of the data for 200% of what its share of the cost would have been had the program been conducted for the Joint Account. The change was made because that structure potentially encouraged non-participation, as a Non-Participating Party knew it had the option to acquire the data if it matured a prospect.

ii) Parties in a large regional area of mutual interest involving a significant joint exploration program may wish to deviate from this approach. They might include an obligation to allow participation in any G&G program within the project area. They might also provide that a Party could not participate in a well within the program area without acquiring the data at a prescribed amount (such as 200% of what its share of the cost would have been had it been conducted for the Joint Account), unless it had its own data over the prospect.

Clause 10.12: i) The Clause does not include an allocation of capital costs or a fee for capital. A capital component would delay the prescribed cost recovery, even though there would be an immediate benefit (income) to the Non-Participating Parties. It would also be inconsistent with the basis for use of excess capacity contemplated in Clause 14.03. The Participating Parties do not have preferential rights to use production infrastructure that falls outside the definition of Production Facility. Any such use would be on such terms as the applicable Parties may negotiate at the time.

ii) An Independent Well on the Joint Lands has priority for use of excess capacity in a Production Facility held for the Joint Account over an existing owner well using it for Outside Substances. This is because production from the Independent Well can ultimately benefit the Joint Account due to the acceleration of the cost recovery. Joint Account wells have the highest priority, even if drilled subsequent to an Independent Well or outside well.

Clause 10.13: i) If the construction of a minor production facility is proposed for wells operated under the 1974 or 1981 document and fewer than all Parties with interests in the wells that would use it participate, the non-participants would either take their production to some other facility or negotiate a processing/transportation arrangement with the facility owners (if sufficient capacity in the facility is available). Production Facility provisions were introduced in the 1990 document to address these types of issues (Clauses 1021 and 1022 of the 1990 document).

Clause 10.13 expands the options for Parties that do not wish to participate in the Production Facility. It provides the Parties proposing to construct a Production Facility with the opportunity to achieve greater participation and use of the facility. However, these provisions do not require that all Production Facilities must be subject to an Operation Notice or constructed for the Joint Account.

Subclauses 10.13A and B are enabling provisions. They do not preclude the Parties from entering into a separate agreement to construct or use this infrastructure. They allow any Party to propose the construction of a Production Facility through an Operation Notice. Parties receiving that notice have the option to: (a) participate; (b) elect not to participate and take their production in kind; (c) elect not to participate and be subject to a cost recovery out of their production of Petroleum Substances handled at the Production Facility: or (d) if Paragraph B(d) is selected to apply, negotiate a fee to use the facility on the same basis as provided under Clause 14.04. The definition of Non-Participating Party provides that a Party that makes the take in kind election in Paragraph B(b) or a fee election under Paragraph B(d) is not a "Non-Participating Party". In the context of a Production Facility, a "Non-Participating Party" is a Party that elects to be subject to a cost recovery as a result of its non-participation under Paragraph B(c).

Any cost recovery would usually be paid out of production from wells located on the Joint Lands and using the Production Facility. Upon recovery of the prescribed cost recovery, the Non-Participating Parties have a further election whereby they may choose to reject or accept participation in the facility, with rejection amounting to forfeiture of the rejecting Party's interest in the Production Facility.

The main principle in this Clause is that the construction of a Production Facility should be permitted. This is subject to the critical qualification that no Party is forced to participate in the facility, either directly (by paying its share of costs in cash) or indirectly (through a cost recovery mechanism).

ii) Subclause 10.02A of the 2007 document was modified, so that it does not include a sentence like the first sentence of this Clause. It has been retained in this Clause to encourage dialogue, as decisions about Production Facilities can affect an entire development project.

iii) There are some practical implementation issues associated with the take in kind option for such matters as compensation for shutting in production, surface sharing and liability and indemnification. Other than for the inclusion of a mutual liability and indemnification obligation, it is not feasible to be prescriptive about them because of the degree to which these types of issues are situation dependent. These issues seem manageable in practice because of the Operator's role in conducting any work required to accommodate the election, particularly with a fallback into the Subclause 10.13J fee if issues are unresolved and the electing Party ends up not taking in kind.

iv) Paragraph B(d) was introduced in the 2007 document, and modified to an optional Paragraph in the 2015 document. The fee option would probably be considered by the Parties in practice in any event. The option may be mutually attractive because of the difficulties inherent in monitoring a facility payout account, particularly if there are multiple Participating Parties and the production is gas and associated products. It may also be attractive if a Party is not interested in acquiring its full share of capacity in the facility because it is not as optimistic about well performance as the proponents (e.g., regards one well as uneconomic). In that case, the option may sometimes provide a platform for negotiation of an arrangement involving a lower level of participation in the Production Facility. In practice, a Proposing Party would often identify its expectation for the fee in the Operation Notice, even though it cannot unilaterally impose its fee. A Receiving Party considering the fee option would presumably initiate a discussion before expiry of the response period if the notice were silent.

v) Only Operations that would result in a facility meeting the tests in the definition of Production Facility are within the scope of this Clause. A Party that receives a notice for an Operation that does not satisfy those tests may reject the notice. The 2007 document introduced more protection for the Receiving Parties. A Receiving Party has 10 Business Days to notify the other Parties of its objections if it does not believe that the Production Facility meets the requirements in the definition of Production Facility (e.g., an objection that it is overdesigned to handle Outside Substances). Any such objection suspends the response period for the Operation Notice pending a determination under the Article 21.00 dispute resolution process.

Subclause 10.13D: i) This Subclause addresses the cost recovery process. A Party that elected to take in kind or, if applicable, pay a fee does not fall within the definition of Non-Participating Party. In essence, the Participating Parties will retain the Non-Participating Party's share of production from wells held hereunder that use the Production Facility until recovery of the prescribed amount. As is the case with the calculation under Clause 10.07, the current expenses for royalties, Operating Costs and Facility Fees are deducted before the allocation of remaining proceeds to the outstanding capital amount.

ii) Paragraph (c) recognizes that the Production Facility may be designed to provide only partial handling functionality, as additional product enhancement may be required at other upstream or downstream facilities. This could happen, for example, if the Production Facility provided field booster compression where the production requires further downstream handling.

iii) An-Participating Party may already be subject to a Clause 10.07 cost recovery for a well using the Production Facility. The Clause 10.07 cost recovery would take priority over the Clause 10.13 cost recovery. If the Non-Participating Party's interest in other wells hereunder were subject only to the Clause 10.13 cost recovery, it would then initially be from those wells. If the Clause 10.07 cost recovery were attained before the Clause 10.13 cost recovery, the Clause 10.13 cost recovery would then apply to that Non-Participating Party's interest in that well.

Subclause 10.13E: i) A Non-Participating Party has the option to pay in cash the outstanding amount to be recovered from its share of production. The tax impact here would be based on an acquisition of tangible property (not "COGPE"), and includes the requirement to pay GST on the acquisition. (This would be based on the gross (100%) outstanding amount of the cost recovery amount as prorated to that Party's Working Interest.) This may be attractive to a Non-Participating Party if it wishes to participate in additional development drilling that will result in an increased use of the Production Facility. This option could also be particularly attractive if an expansion is being considered under Clause 10.14 to accommodate increased volumes of Petroleum Substances.

The Participating Parties could also find the exercise of this right attractive because common equity interests early in the development cycle can facilitate pool development. The Participating Parties can benefit from a near term receipt of funds (versus receiving production proceeds over time on a less favourable tax basis) and from participation in the lower rate of return Production Facilities. Payment also shifts the risk for pool performance on the interest from the Participating Parties to the former Non-Participating Parties.

ii) A Non-Participating Party considering the exercise of the acquisition right granted under this Subclause would typically conduct a due diligence review to confirm that the Production Facility is consistent with its expectations.

iii) Although the Participating Parties would probably be receptive to this for Production Facilities constructed under the 1990 document, this mechanism was introduced in the 2007 version of the document.

Subclause 10.13F: Subclauses 10.07F, G and H and 10.09B apply, *mutatis mutandis*, to Clause 10.13. This ensures that the cost recovery infrastructure in Clause 10.07 and the Abandonment processes in Subclause 10.09B apply to the Production Facility.

Subclause 10.13G: A Non-Participating Party that elected to be subject to the cost recovery might elect not to obtain an interest in the Production Facility after the cost recovery because of its belief that reclamation costs would exceed the value of the Production Facility to it. The elections to accept participation in the well and in the Production Facility are distinct elections. It could accept participation in the wells, but refuse participation in the Production Facility. It would then have to negotiate a fee if it wanted to use the Production Facility for its share of production from the Joint Lands.

Subclause 10.13H: A former Non-Participating Party that exercises its right to acquire its Working Interest by paying the outstanding cost recovery amount in cash acquires its Working Interest in the Production Facility, effective as of the date of that payment and subject to Paragraph 10.13E(d). Once it becomes an owner, it shares the rights and responsibilities on the same basis as if it had originally been a participant in the activity. For example, it would assume its share of any outstanding claims against the owners and its share of the benefit of any revenue adjustment in favour of the owners during the period prior to the time it became an owner.

Subclause 10.13J: This Subclause provides the necessary fee mechanism if a Party that elects to take its production in kind fails to do so. The provisions of Article 6.00 also apply to the extent that this occurs, except for a doubling of the Clause 6.04 marketing fee. This structure is premised on a *bona fide* election and a temporary failure to take in kind. The construction is not intended to enable a Party that has no intention to take in kind to make the Paragraph B(b) election. There may be instances in which the Parties chose to modify this Subclause so that the Participating Parties have the option to terminate the Paragraph B(b) election and replace it with a Paragraph B(c) election if the electing Party fails to begin to take in kind within, for example, 12 months following the completion of the installation of the Production Facility.

Clause 10.14: i) This Clause applies the Clause 10.13 principles to the expansion of an existing Production Facility, subject to Clause 14.02. If this occurs, an owner's options are limited to participation or being subject to a cost recovery, with no further election after recovery of the prescribed amount. That Party does not have the right to forgo acquiring its interest in the expansion after the cost recovery, as this would require the creation of functional units with different ownerships and greatly complicate management of the Production Facility.

This mechanism deviates from the principles that apply to a significant facility under a typical, detailed facility agreement, such as the PJVA CO&O Agreement. It would not force a non-participating owner to participate in an expansion or to pay for it indirectly through a cost recovery. Because of the unique handling and to encourage dialogue, the 2007 document was modified to decrease an expansion cost recovery from 200% to 150%.

When considering this principle, it is important to remember that the Operating Procedure is only intended to apply to a minor facility for which the Parties choose not to prepare a separate facility agreement. The application of a cost recovery to minor expansions of such a Production Facility allows it to continue to be governed by the Operating Procedure. Parties that find this objectionable, however, may prefer to: (a) try to negotiate an alternative in the context of their situation; (b) prepare a separate facility agreement; or (c) delete this portion of the provision and modify Clause 14.02 to exclude any Production Facility being expanded if fewer than all owner Parties agree to the expansion.

ii) A Non-Participating Party in the Production Facility is to be provided a copy of the Operation Notice for the expansion. It has the option under Subclause 10.13E to pay in cash the outstanding amount to be recovered from its share of the production to become a Working Interest owner in the Production Facility. Making that payment before expiry of the response period for the expansion of the Production Facility would then enable it to elect to participate in the expansion as a Working Interest owner.

Subclause 10.15A: i) The Operator of an Independent Operation is to provide the affected Parties (Non-Participating Parties and Participating Parties assuming the Non-Participating Parties' costs) with periodic statements showing the status of the cost recovery under the applicable provision (9.03, 10.07, 10.08, 10.13 or 10.14) once the Non-Participating Party is entitled to information from the Operation under Clause 10.19. Pre-2007 versions of the document included an obligation to issue statements on a monthly basis. This obligation was typically ignored and the cost recovery status monitored infrequently by both the "Operator" and the Non-Participating Parties. The more specific obligations in this Subclause are intended to help address this problem. The obligations are largely based on Clause 6.01 of the 1997 CAPL Farmout & Royalty Procedure. It, in turn, had largely been based on the 1989 PJVA Well Payout Calculation Study.

Having reasonable information of this type on hand is particularly important if a Party is disposing of its interest.

ii) Notwithstanding the expectations set forth in this Clause, industry's implementation of the Clause in practice is likely to be "targeted compliance". There are wells that warrant the administrative effort contemplated by this Clause and those that do not, and both Operators and Non-Participating Parties will govern themselves accordingly in practice. A Non-Participating Party can quickly assess if an Independent Well may be material to it by using public data to look at production rates.

iii) The Operator might only have participated for its Working Interest share of costs and conducted the Operation under Alternate 10.04A(b). The Proposing Party would have the monitoring and reporting obligations under this Clause in that case.

Subclause 10.15B: The cost recovery calculation can be complicated greatly if multiple Participating Parties have assumed the Non-Participating Parties' costs. They would typically sell into different markets at different prices, and the Operator would seldom be aware of the range of actual prices. Their cost structures could also be very different if they have different positions in regional infrastructure used to handle the production subject to the penalty (e.g., facility owner, fee user). The handling of Facility Fees and proceeds in the post-1990 documents mitigates these issues.

Subclause B enables the Operator to use its own cost and revenue information as a proxy for that of the other Participating Parties when doing a 100% calculation. Remember, though, that Subclauses 10.07A and 10.13D generally require use of a "Market Price" for production proceeds.

Subclause 10.15C: The cost recovery is calculated on a financial month basis, with a financial adjustment to accounts. Insofar as there are changes to debits or credits used in the calculation (e.g., delayed recognition of Operating Costs, impact of 13th month adjustment), there will be an adjustment to the Parties' accounts at the time. This approach also applies to adjustments for the period prior to the election to obtain participation.

Subclause 10.15D: A Non-Participating Party has audit rights on the same basis as under the Accounting Procedure, with Clause 21.03 potentially applying to unresolved audit exceptions. Any such audit will also be conducted in accordance with the then most current PASC Joint Venture Audit Protocol. Audit rights extend beyond the Operator of the Independent Operation to the other Participating Parties that assumed the Non-Participating Party's share of costs. In practice, a Non-Participating Party would only even consider the expanded audit if the well was significant to it and there were a concern that the Operator's handling wasn't representative.

Subclause 10.15E: i) One of the historical difficulties with Clause 10.15 has been the lack of consequences for failure to issue the required periodic statements. The 2007 document introduced a mechanism whereby a Non-Participating Party may conduct an audit for the account of the applicable Participating Parties if it does not receive a statement within 60 days after a formal request. A Non-Participating Party is more likely to consider this mechanism if it has previously made several requests for the statement, particularly if the well is potentially significant to it.

ii) Any such audit is at the expense of the Participating Parties that assume the Non-Participating Party's share of costs, even though the "Operator" is the Party that has refused to satisfy the reporting obligation. This structure was designed to encourage performance by causing the other Participating Parties to take greater interest in the problem because they would also be required to bear a share of the cost of non-compliance.

iii) This also provides the Participating Parties with a basis to replace the "Operator". Clause 10.16 applies the other provisions of the document, *mutatis mutandis*, between the Parties. The replacement processes in Subclause 2.02B would apply to an Operator in default of its obligations that does not remedy the default within 30 days after receipt of a default notice from a majority in interest of the "Non-Operator" Participating Parties.

Subclause 10.15F: It is not uncommon for notice of a cost recovery not to be issued to the Non-Participating Parties or to be issued later than it should have been. A Non-Participating Party is entitled to interest on the funds to which it would have been entitled had it elected to resume participation when the notice should have been issued. To provide greater protection to the Non-Participating Parties for the debt owing to them, they also have access to the general default remedies in Clause 5.05.

There is little likelihood that this provision would apply if the required statements were, in fact, being issued under Subclause 10.15A. The most practical impact of the Subclause will be to ensure that there is an incentive for Proposing Parties to comply with that Subclause.

Clause 10.16: It is not well understood that an Independent Operation is basically conducted for the "Joint Account" of the Participating Parties, notwithstanding the special status relative to Non-Participating Parties. This is a very important Clause. It ensures that such provisions as Articles 4.00-9.00 and 16.00 and Clauses 3.04, 3.05, 3.06 and 3.11 apply, *mutatis mutandis*, to the Participating Parties in an Independent Operation.

Clause 10.17: Suppose A, B and C hold respective Working Interests of 50%, 25% and 25%. A elects not to participate in an Exploratory Well, B elects to participate only to the extent of its Working Interest and C elects to assume A's entire share of costs.

As C has assumed A's entire share of costs, the benefits associated with A's penalty (whether cost recovery, Subclause 10.13E cash payment or Clause 10.10 forfeiture) should accrue only to C based on the matching of risk and reward to the incremental interests and costs. In the absence of the first sentence, B and C would allocate the benefit of the penalty between them in the proportions of their Participating Interests because of the second sentence. B would literally receive 25% of the benefit without assuming even $1 of the Non-Participating Party's costs.

The allocation of interests in the first sentence was introduced in the 1990 document. The allocations under Clauses 1010 and 1016 of the 1974 and 1981 documents were stated to be in proportion to the Parties' Participating Interests in the Independent Operation, and many international and frontier agreements use similar language. Notwithstanding this gap, it is unlikely that Parties would dispute this issue in practice if it were discovered in a timely manner. This would probably only ever be an issue if an allocation error either was not recognized or was discovered well after the fact.

Clause 10.18: i) This provision addresses both liability and indemnification. It also applies to Operations conducted by fewer than all Parties under Clause 7.07 and Article 9.00.

ii) The Participating Parties are responsible for Losses and Liabilities suffered by the Non-Participating Parties, insofar as they are caused by the acts or omissions of the Participating Parties, subject to the special handling of Extraordinary Damages under Clause 4.04. The exclusion of Extraordinary Damages provides greater protection to the Participating Parties than existed under all previous versions of the document.

iii) There are circumstances in which it would be arguable that a Non-Participating Party had contributed to the loss by its actions or omissions.

iv) The Clause also applies to the Participating Parties and a Receiving Party that exercises its right to take in kind or pay a usage fee under Subclause 10.08F or 10.13B.

Clause 10.19: i) The 2015 document contemplates that the Parties may prescribe a different outcome in the Agreement with respect to non-participation in a Multiple Well Drilling Program, a Multiple Well Completion Program or the development of a Well Pad. Otherwise, information from an Independent Well will initially be withheld from a Non-Participating Party. Except for Clause 10.10 wells and subject to Paragraph 5.05B(b) (withholding of information due to a default), a Non-Participating Party will generally be provided the existing information at the earlier of the date it becomes a Participating Party or the date prescribed by Paragraph (a) or (b).

For drilling information from a new well or a Deepening or Sidetracking, the Operator will provide a Non-Participating Party with the drilling information prescribed by Clauses 7.02 and 7.03 150 days after the applicable drilling rig release date. (This is basically a 60 day increase relative to the pre-2007 versions of the document.) For this purpose, a Deepening or Sidetracking conducted on a well prior to its initial drilling rig release is regarded as a single, continuous Operation. A Deepening or Sidetracking conducted in conjunction with the re-entry of an existing well is regarded as a distinct Operation, such that a Non-Participating Party in the entire well would receive the applicable drilling information on a staged basis.

Paragraph (b) handles Completion and production information differently than in the pre-2007 versions of the document. A Non-Participating Party is entitled to receive that information at the later of: (a) the date prescribed by Paragraph (a), if applicable to that Non-Participating Party (i.e., a Non-Participating Party in the initial applicable drilling Operation); and (b) 90 days after the conclusion of the applicable Completion, Recompletion or Reworking. This structure addresses a problem in prior versions of the document in circumstances in which the participation differed. (A Non-Participating Party in the entire well could sometimes obtain Completion and production information before a Party that participated in drilling the well, but not its Completion.)

ii) To illustrate the application of the Clause, assume that A elected not to participate in the well, B participated in drilling the well, but not the Completion of the well and C participated in all Operations. A would be entitled to the drilling information 150 days after the rig release date of the well. It would be entitled to Completion information at the later of that time or 90 days after conclusion of the Completion (i.e., it would obtain Completion information 180 days after rig release if the Completion concluded 90 days after rig release). B would obtain the drilling information on a current basis because of its participation in the well. It would obtain the Completion information 90 days after conclusion of the Completion, such that it would receive the Completion data at the same time as A.

iii) The timing of the release of well information is subject to four qualifications. Firstly, the Participating Parties may choose to release information to accelerate elections under Subclause 10.02F for an additional well within 3.2 kilometres of a well drilled hereunder. Secondly, the Non-Participating Parties may have access to some of the information earlier from regulatory authorities insofar as the confidentiality period for the information under the Regulations is shorter than that provided under this Clause. Thirdly, there is an obligation to provide Completion type information that is subsequently acquired. Fourthly, the obligation does not apply to information from wells that have an experimental status under the Regulations (i.e., certain unconventional gas wells), to recognize the commercial sensitivity of disclosure of information from those wells.

iv) The reference to the date a Non-Participating Party becomes a Participating Party pertains to a cost recovery under Clause 9.03, Subclause 10.07A or Clause 10.08. A Non-Participating Party never becomes a Participating Party for a D&A Independent Well. The delayed receipt mechanism in this Clause always applies to a D&A well.

v) The obligation to provide information to a Non-Participating Party relates to the specific well, and does not apply insofar as Clause 10.10 applies to the well. There are two subtleties about this construction. The first is that the obligation to disclose the information would not apply to any portion of the well to which the Clause 10.10 penalty applied, but would apply to the extent that the cost recovery mechanism (i.e., Clause 10.07) applied to a portion of the well. The second is that the test is linked to the penalty on the well, rather than to the status of the well as a Title Preserving Well. A Title Preserving Well, for example, that is drilled on lands that are not expiring, but which preserves other Joint Lands, would not relieve the Participating Parties from the obligation in this Clause.

vi) Users should be aware of the pending obligation to release data for wells when considering acquisitions of additional lands at Crown sales or from third parties. A Party, for example, would not want to cause offsetting lands to be offered at a Crown sale 160 days after the rig release of an Exploratory Well, as the Non-Participating Parties would have access to the well information prior to that sale.

vii) The Regulations respecting the release of well information can vary materially by jurisdiction. Prudent Parties should understand those Regulations when planning drilling programs in jurisdictions in which they do not have significant recent experience.

Clause 10.20: The Participating Parties could also be negotiating tract factors/pooled interests for other lands in which they have an interest. They may only unitize or pool a well subject to a cost recovery with the Non-Participating Parties' consent, which may not be unreasonably withheld. Ultimately, this reflects the fact that the cost recovery does not alter the Working Interests in the applicable Joint Lands.

Some of the issues to be considered by the Non-Participating Parties for a pooling would be the allocation of production, clarification of the impact of the financial arrangement on the cost recovery calculation, the material provisions of a pooling agreement (i.e., cross-conveyance or no cross-conveyance, the pooled substances/zones, the treatment of encumbrances and the elections under the Operating Procedure).

Clause 11.01: i) The surrender process is distinct from the process of not participating in a temporary continuation or extension of a Title Document for an incremental fee under Subclause 3.10E (e.g., an Alberta Section 17 one-year continuation).

ii) Failure to respond is deemed to be an election to retain, which has been the presumption since the 1971 document. A non-responsive Party that discovers that it is acquiring interests it does not want would typically respond very quickly in practice. The net effect of a quick phone call after expiry of the election period would probably see prompt confirmation of the surrender. (See also Clause 12.01.)

iii) All of the pre-2007 versions of the document included a revocation up to the end of the election process. The last sentence modified this approach as of the 2007 document, and allows a Party to change its election not later than three Business Days after expiry of the response period if at least one Party elects not to join in the surrender. This could place an additional administrative burden on the Operator/Title Administrator if it calculated the revised interests prior to expiry of the response period. However, the provision should not pose a problem in practice. It is likely to minimize that burden because its most likely application would be to the case in which the Party that proposed the surrender reversed its position after seeing that the other Parties elected to retain their interests. It would be most likely to consider the exercise of this right if the surrender involved only a portion of the Joint Lands. The sentence ultimately reflects a policy objective of allowing Parties to continue to hold the Joint Lands jointly, to avoid segregation issues and other potential equity issues over time. (See also Clause 12.01.)

Clause 11.02: i) A Production Facility may be a profit centre for Outside Substances, so a Party would generally retain its interest therein. A Production Facility might be managed outside the Operating Procedure under a separate CO&O Agreement at this stage because of Clause 14.02.

ii) The Title Administrator would process the surrender with the lessor if it is a Party other than the Operator.

iii) A surrender by all Parties does not release them from any accrued liabilities, such as Abandonment obligations or other Environmental Liabilities. The Agreement will continue to apply to those liabilities. Otherwise, the Operator could initially be responsible for them and potentially find itself attempting to recover amounts several years later when some of the other Parties are reluctant to assume their share of those costs.

Subclause 11.03B: i) The surrender is effective on the day before the obligation date. Subject to the limited revocation election, the Parties' contractual rights would have crystallized 30 days before this date under Clause 11.01.

ii) Unless otherwise agreed by the retaining Parties, the transfer will be in proportion to their Working Interests.

iii) The transferors' share of the estimated net salvage value of the material and equipment on the surrendered lands, less their share of the Abandonment costs of any associated wells and other applicable Joint Property, is to be determined within 30 days after the deemed assignment. Accounts will be adjusted accordingly within 30 days after this determination, with the matter potentially referred to arbitration under Article 21.00 for resolution insofar as they are unable to agree. Parties owed an amount will have access to the remedies in Clause 5.05 if accounts have not been adjusted at that time. Subclause 5.05D ensures that a Party owed an amount retains other legal remedies for any amount owing to it.

This could require the surrendering Parties to pay an amount to the retaining Parties if the estimated Abandonment costs exceed the estimated net salvage value of the assigned material and equipment. This mitigates the risk that a Party would surrender to attempt to avoid Abandonment costs.

iv) The assignment under this Article occurs through operation of the Operating Procedure, such that no separate notice of assignment is required because of the second sentence of Clause 24.04. Some Parties may still prefer to complete a notice of assignment after a surrender to optimize the paper trail on the file, particularly if there will be segregation (Article 13.00) as a result of the surrender. They need to remember, though, that the use of a NOA would defer the timing for the transfer of responsibility of obligations for the surrendered lands.

Some documentation may be required to reflect the assignment, though (e.g., a Crown mineral transfer or a trust agreement).

Subclause 11.03C: A surrendering Party is not released from obligations that accrued prior to the surrender (including Environmental Liabilities, obligations with respect to approved Operations and those associated with an emergency) and its obligation to maintain information confidential. However, this does not extend to the obligation to Abandon any well on the lands so assigned, since the estimated Abandonment cost (including reclamation costs associated therewith) was taken into account under Subclause 11.03B when the accounts of the Parties were adjusted.

Subclause 11.03D: Assume that A, B and C acquire a licence and that A subsequently surrenders its Working Interest in half of it to B and C. B and C acquire certain obligations with respect to those lands, where failure to perform some of those obligations could compromise the ability to retain the rights jointly held with A in good standing. If, for example, B and C did not surrender the acquired lands and then failed to pay rentals or a lessor royalty, the entire Title Document would be in jeopardy.

B and C are therefore required to maintain the lands surrendered by A in good standing if failure to do so could prejudice A's title to the retained portion of the licence. However, they are never obligated to conduct an Operation on the lands they acquired through the surrender.

Clause 12.01: i) The addition of the first sentence reflects the increasing use of Well Pads and the likelihood that the Abandonment of a Well Pad could be occurring on a staged basis. There will be circumstances in which the size of a potential Abandonment program for a regional shale project is such that the Parties include special provisions in their Agreement to address Abandonment security. There will also be circumstances in which the differences in equity ownership between the wells on a Well Pad are such that the applicable owners will have negotiated a separate agreement to manage their relationship with respect to the Well Pad.

ii) The interrelationship between this Clause and Clause 10.08 Recompletions has historically not been well understood by users. Assume that a joint well is no longer capable of production in Paying Quantities from the Z formation when one Party believes that an uphole Recompletion should be pursued in the T formation. It should propose a Recompletion under Clause 10.08 in which one component of the Operation is the plugging of the downhole portion of the wellbore. The costs of the downhole abandonment are within the scope of the definition of Recompletion, so those costs would be included in the associated Paragraph 10.07A(e) amount if a cost recovery applied to the Recompletion.

iii) See the annotations on Clause 11.01 about failure to respond. In practice, a quick phone call could often see confirmation of the Abandonment.

iv) The second last sentence was introduced in the 2007 document. Any Party may revoke its notice to participate in an Abandonment not later than three Business Days after expiry of the 30-day notice period if at least one Party has elected not to join in the Abandonment. (See the annotations on Clause 11.01 for additional context on this right.) Notwithstanding that this process may result in the election not being finalized for several days after expiry of the election period, the assignments are deemed to be effective as of the end of the election period, so that there is consistency in the preparation of assignment documentation. This also allows for an earlier release for the Abandoning Parties.

v) A Party may not serve notice to Abandon a well during a period in which there is an emergency respecting that well. Similarly, any such notice will be void if an emergency occurs during the response period.

vi) The Abandonment obligations for a Production Facility are embedded in the definition of Abandonment and Clauses 1.14, 3.04 and 3.05.

vii) The handling of financial approvals following an election by all Parties to Abandon a well has historically been a "chicken and egg" scenario. The Abandonment notification process would typically be initiated by the Operator. However, that is not necessarily the case, and a Non-Operator would not be well positioned to issue an AFE for the Abandonment with its notification. Similarly, the uncertainty resulting from the election process is such that an Operator would be unlikely to have investigated fully the location and the integrity of the wellbore before it issued an Abandonment notice.

The traditional industry practice was a layered approach, in which the Operator would forward an AFE in due course after the determination that the well was being Abandoned for the Joint Account. The gaps in that process were that the AFE might not fully reflect the specific circumstances and that a Party could potentially choose not to approve the related AFE for a well it had agreed to Abandon. Additional AFEs would be required in due course for subsequent reclamation and remediation activity.

Given the fact that well specific information will only be known after the Operator's investigation of the site and the integrity of the wellbore, the 2015 document was modified so that any resultant AFE is for informational purposes only. There was a consequential change to Paragraph 3.01B(b).

viii) The Parties will need to manage the Abandonment process carefully if one of the Parties is in receivership under the protection of the *Companies' Creditors Arrangement Act* (Canada). See Baytex Energy Ltd. v. Sterling Eagle Petroleum Corp., [2012] A.J. No. 916 (Alta. Q.B.). In an Alberta context, the Parties should become familiar with the requirements of the Alberta "Orphan Well Fund", which currently sees the Operator make a claim after the required work is complete and a delay in the recovery of funds. There will be circumstances in which the most expedient way to address the issue will be for the Operator to assume the incremental costs for its own account. There will be others in which the magnitude of the costs and the time at which costs would be expected to be recovered from the fund are such that the Operator will require the other Parties to share this burden proportionately under Clause 5.06. (See also Article 23.00 when dealing with a "delinquent Party".)

Clause 12.02A: i) The purpose of the Abandonment Article is to enable the retaining Parties to continue to use the wellbore for exploitation of the producing/Completed formation(s). Other than for forgoing their share of production from that formation through that well, the Abandoning Parties' rights for the Joint Lands included in the Spacing Unit remain unchanged. The Abandoning Parties have Working Interest rights if the retaining Parties subsequently choose to use a different wellbore to exploit that formation at a different location in the Spacing Unit. A Sidetracking into the same formation would involve the use of a different wellbore because of the incremental drilling activity to a different location in the formation. In essence, the Abandoning Parties have a Working Interest in the formation, but no interest in the well or the associated production.

ii) There is an adjustment of accounts to reflect the estimated Abandonment costs under Subclause 12.02B. Subject to the application of Article 15.00 to encumbrances not borne for the Joint Account, the retaining Parties basically acquire the assigned rights on an "as is, where is" basis and assume full responsibility for all Environmental Liabilities with respect to the assigned interests, regardless of when they may have accrued (Subclause 12.02C). This is consistent with the result in industry's typical A&D transactions.

Notwithstanding that general outcome, there may be some circumstances in which the Parties negotiate a different outcome because of some known Environmental Liabilities, particularly if reclamation work is then ongoing for an incident off the well site.

iii) Unless otherwise agreed by the non-Abandoning Parties, the assignment will be in proportion to their Working Interests.

iv) The Regulations increasingly include restrictions on well licence transfers whereby certain assignees may be precluded from accepting a transfer of the well licence. The Parties need to review these restrictions at the time of any proposed assignment of a well licence under this Article. The Operator would need to be eligible under the Regulations to accept the transfer of the applicable well licence.

If none of the retaining Parties would be eligible to accept a transfer of the well licence under the Regulations, each Party will be deemed to have elected to join in the proposed Abandonment and the Operator will proceed with Abandonment, unless otherwise agreed by the Parties. Notwithstanding that statement, the Parties would, in practice, be mutually motivated to consider how best to address this at the time in the context of their particular circumstances and the Regulations then in effect in the applicable jurisdiction.

v) The limited assignment of a Working Interest under this Article occurs through the operation of the Operating Procedure, such that no separate notice of assignment is required because of the second sentence of Subclause 24.04A. The preparation of a notice of assignment could also create confusion, as the Working Interests in the Joint Lands are not being altered. However, some documentation may be required to reflect the assignment under this Clause, particularly if the Operator is an Abandoning Party (e.g., a transfer of the well licence, a transfer of the applicable surface dispositions and obligations and any applicable equipment rental or service contracts). It is also important for a new Operator under this Clause to ensure that notices are distributed to other affected third parties for such matters as utilities and municipal taxes, and that signs are modified. In many ways, the assignment process should be managed in the same manner as an A&D transaction.

Subclause 12.02B: The transferors' estimated net salvage value of the material and equipment for the well, less their share of the Abandonment costs of the well, is to be determined within 30 days after the transfer. The Parties' accounts will be adjusted accordingly within 30 days after that determination, with any dispute potentially resolved ultimately through arbitration in Article 21.00.

This calculation would require the transferors to pay an amount to the retaining Parties if the estimated Abandonment costs exceeded the estimated net salvage value of the assigned material and equipment.

Subclause 12.02C: Subject to Clause 12.03, the non-Abandoning Parties generally assume all obligations accruing for the well after the takeover. However, the Abandoning Parties are not released from their future share of costs for any emergency that had occurred prior to the transfer, other than to the extent already included in the adjustment of accounts.

Clause 12.03: The Abandoning Parties assigned their interest in the well and their Working Interest share of Petroleum Substances produced through the well from the Completed formation. They otherwise retain their Working Interests in the Joint Lands, such that they have participation rights for Operations in other formations or a Sidetracking in the same formation. They will have a participation right under Clause 10.08 if the retaining Parties later use the well for an uphole Operation. This participation right includes the ability to acquire a Working Interest in the well that corresponds to their Working Interest in the applicable Joint Lands, with a resultant adjustment of accounts on the same basis as prescribed by Subclause 12.02B. This basically sees them reacquiring a Working Interest in the well for little incremental consideration. This reflects the fact that there had been a previous adjustment of accounts for the well through which the retaining Parties acquired their incremental interests for a low cost (i.e., after an adjustment for Abandonment costs applicable to the assigned interest). This mechanism is designed to put the Parties in the same position as they would be in if a plugging back and uphole Recompletion were initially presented.

Clause 13.01: i) The application of the document to the heterogeneous ownership case can be confusing. The Clause applies if any portion of the Joint Lands: (a) ceases to be held in the same percentages as the Working Interests in the balance; (b) is held by fewer than all Parties; or (c) is held by a mix of different Parties. In essence, each common Working Interest portion of lands will be held as if the applicable owners are Parties to a separate agreement having the same terms, except for the change to the interests/Parties. An Article 9.00 or 10.00 cost recovery does not result in segregation, as the Working Interests in the Joint Lands remain unchanged during the cost recovery.

This provision and Subclause 24.04B reflect a CAPLA initiative on the segregation issue. This Clause is similar to the provision in the pre-2007 versions of the document, other than for: (a) the use of the reference to the "Agreement", instead of the "Operating Procedure"; and (b) the presentation of parallel agreements, rather than a parent agreement and a spinoff agreement as in pre-2007 versions of the document. The biggest impact will be in the third parties identified in a notice of assignment. It will often see the NOA for a partial assignment delivered only to the same Working Interest Parties that receive notice of the disposition under Clause 24.01, an administrative practice that has already been commonly used.

ii) To illustrate the impact of this provision, assume that the Parties' Working Interests in sections 1 and 2 were initially held by A, B and C, and that A and B later acquired all of C's interest in section 1 because of a forfeiture. B is now proposing to dispose of its entire interest in both sections when there is a ROFR obligation. B would serve one ROFR notice to A for section 1 and a separate ROFR notice to A and C for section 2, as each section is treated as being subject to its own Agreement. This is the same outcome as would have occurred in previous versions of the document.

iii) Not all changes of interest will be through a NOA due to an Article 24.00 disposition. Other transfers of interest can occur by operation of the Agreement, such as a Clause 10.10 forfeiture, a surrender or an Abandonment. Those provisions state when that change is effective.

iv) The document does not prescribe the manner in which a Party manages "separate agreements" in its records system. Most Parties would probably manage them simply as "splits" in their contracts database.

v) This provision also applies, *mutatis mutandis*, to a Production Facility, assuming that it is not governed by a separate CO&O agreement. In practice, a Party would typically elect under Clause 14.02 to have such a Production Facility managed under a separate CO&O agreement if it was concerned about use of the Production Facility to handle production with differing ownership. It could do this because all production using the Production Facility would be regarded as Outside Substances for the purposes of the segregated agreement that was created for the Production Facility.

vi) A Party assigning an interest when this Clause applies must be aware of any special issues that could arise because of the creation of a segregated block. Issues relating to such matters as an outstanding area of mutual interest, joint Production Facilities and, if stratigraphic segregation, the handling of existing wellbores, would need to be addressed on a transaction specific basis. Given the complexities potentially associated with this Clause, the affected Parties may sometimes find it helpful to supplement the Clause with a letter agreement that addresses more specifically the outcomes in their particular situation.

vii) There is a consolidation of separate agreements insofar as lands in different agreement splits are again held in common Working Interests.

Article 14.00 (General): i) Production facilities of any significance, in terms of capital investment, capacity, risk or complexity, should be governed by individual facility agreements. There will always be a class of minor facilities, though, that does not justify the time and expense to create specific agreements, such that owners often construct, own and operate a minor production facility without any agreement specifically intended to cover those activities. Prior to the 1990 document, the applicable owners often purported to apply the terms of the Operating Procedure governing the lands served by a facility to administer their relationship for the facility, even though the facility was outside the document scope.

Article 14.00 provides some basic terms required for the construction, ownership and operation of such minor facilities. Situations that demand more extensive terms should be addressed in a separate facility agreement. The initiative of the PJVA to develop the 1996 PJVA CO&O Agreement and subsequent updates has greatly simplified the process of preparing asset specific facility agreements.

For simplicity and to recognize actual operating practices for existing minor facilities, this Article has been limited to items of universal application to that minor class of facilities. The Article deviates from the "norm" found in formal facility agreements in some instances to reflect the nature of the facilities for which it is designed. For example, owners are not charged a capital fee for using surplus capacity in this Article. While not ideal from a "fairness" objective, this reflects the administrative burden management of a traditional fee for this type of facility would place on the Operator.

This Article will seldom apply to significant facilities in practice, so it is not appropriate to address all of the issues normally included in CO&O agreements. Parties that are uncomfortable with this should prepare a separate CO&O agreement in each such case, and Clause 14.02 will also see some Production Facilities later ceasing to be governed by this Article. To provide a depth of coverage comparable to that included in a CO&O agreement would have encouraged Parties to use the Operating Procedure when they should be using a CO&O agreement.

ii) Parties need to remember that the segregation concepts in Article 13.00 can also apply to a Production Facility.

iii) The Abandonment obligations for a Production Facility are embedded in the definition of Abandonment and Clauses 1.14, 3.04 and 3.05. It is unlikely that a Production Facility of significance would be Abandoned under this document, though. It is far more likely that such a facility would then be subject to a separate CO&O agreement because of Clause 14.02.

Clause 14.01: This provision establishes the basis of ownership for a Production Facility. It is subject to Clauses 10.13 and 10.14, the independent facility and expansion provisions.

Clause 14.02: i) As noted in the general annotation above, this Article is structured to address minor facilities that are initially used only for Petroleum Substances from the Joint Lands. The use of the Production Facility for Outside Substances may later increase to the extent that the simple processes in the Article are no longer appropriate. This Clause was introduced in the 2007 document. It creates triggering mechanisms whereby a Production Facility ceases to be a Production Facility and must be managed under a separate CO&O agreement based on the most recent PJVA model and the Accounting Procedure. This was a major improvement to the 1990 document that was made possible by industry's broad acceptance of the PJVA model. The Parties always remain free to use a different form of CO&O Agreement at the time (i.e., a previous version of the PJVA form).

There are three triggering events. The first is that any Party may, by notice, request this result if the Production Facility will be used to handle the Outside Substances of a Party or a third party (including any resulting from a segregated agreement created under Clause 13.01). A Party would typically only exercise this right in practice if it regarded the negative economic impact of that use on it as warranting the effort required to prepare and administer a CO&O agreement for the facility. The second is that any agreed expansion will automatically cause this outcome if the expanded facility would then be used to handle Outside Substances or it no longer satisfies the condition in Paragraph (d) of the definition of Production Facility (e.g., no fractionation of Petroleum Substances), to recognize the resultant change in the nature of the facility. The third is that the Parties may agree to create a new agreement.

ii) The Parties are always free to agree to allow the document to apply for longer than the periods specified by Paragraphs 14.02(a) and (b).

iii) The Clause does not allow the provisions of the Operating Procedure to "bridge" any gap that may occur if a separate CO&O agreement is not in place on the date that construction relating to any significant expansion Commences. The Parties should attempt to ensure that the Commencement of the facility expansion coincides with completion of the CO&O agreement or that they have bridging documentation.

iv) The preparation of the contemplated CO&O agreement would be complicated significantly if a cost recovery then applied under Clause 10.13 and 10.14, as the Non-Participating Parties' future rights for the facility would not be eliminated by this change in status. However, a Non-Participating Party may find it attractive to pay in cash under Subclause 10.13E the outstanding cost recovery amount applicable to it to obtain its Working Interest earlier. This is particularly so for an expansion.

v) While the other provisions of the Article still accommodate continued use of a Production Facility for Outside Substances, this will probably only occur in practice if the use and the associated fees and costs are relatively insignificant.

Clause 14.03: i) Subject to Clause 14.02 and any agreement made under Clause 14.04, this Clause prescribes a Party's rights to use a Production Facility with respect to primary capacity, surplus capacity and priority of use. Production Facilities, by definition, are initially intended to be designed and used exclusively for the production, processing, transportation, etc. of Petroleum Substances produced from the Joint Lands. However, it is a recognized principle of ownership in any facility that an owner may use its capacity and any available surplus capacity to handle its hydrocarbons, regardless of source, as long as the other production is consistent with the facility's operating parameters. The handling of Petroleum Substances produced from the Joint Lands takes priority, though. To simplify the administration of these minor facilities, no capital fee is charged to any Party using surplus capacity, as the resulting fees would generally not justify the associated administration. However, a Party concerned by the degree of use of surplus capacity is free to try to negotiate a different outcome using the leverage available to it under Clause 14.02.

ii) Parties that wish a different outcome without creating a separate CO&O Agreement could modify the provision to include a Paragraph (c) like the following: "any Party using such surplus capacity in excess of its owned capacity in a month will pay a fee for that use to those Parties owning it on the same basis as contemplated in Subclause 14.04B. The Operator will: (i) credit the capital component of any such fee to the Parties on a monthly basis in proportion to their respective contributions of that surplus capacity; and (ii) make any required adjustment to that credit distribution for the preceding year within 180 days after the end of that year." This logic might also be extended to Clause 14.04 fees.

Clause 14.04: i) Significant third party usage of Production Facilities should not occur because of the definition. However, some custom handling of Outside Substances is expected during the life of a facility. Clause 14.04 provides a foundation for this <u>if</u> a separate CO&O agreement is not created under Clause 14.02. This ensures that all facility owners agree to the arrangement and share in the resultant benefits.

ii) To simplify the administration of these minor facilities, the foundation principle is that the capital component of fees received for the custom handling of Outside Substances will be allocated among the facility owners in proportion to their ownership interests. The operating cost component of the fee is credited to the Operating Costs for the Production Facility.

This treatment is different from industry practice for significant facilities under CO&O agreements. They allocate the capital component of fees based on the surplus capacity contributed by each owner to handle those Outside Substances. The approach under this Clause is a generally accepted method of allocating those fees for minor facilities. If this outcome is objectionable to the Parties, it is a good indication that the Production Facility might best be managed under a separate CO&O agreement. Clause 14.02 facilitates this result.

iii) The requirement that third party fees be determined by all Parties could pose a problem if there are a large number of Parties and some hold small interests. The provision addresses part of this concern by including a mechanism under which a Party's approval is deemed if it does not object to the proposed arrangement within 10 Business Days after receipt of the Operator's notice. (The deemed affirmative outcome is also consistent with the result in the PJVA CO&O Agreements.)

The ability to apply the dispute resolution process (Article 21.00) to a disputed third party fee under Clause 14.08 also mitigates the possibility that the Parties would be unable to resolve the matter in practice. However, it sometimes may be beneficial to modify the provision to include some type of voting mechanism.

iv) The Parties may sometimes find that the cost of handling Outside Substances materially exceeds the cost of handling Petroleum Substances. This may already have been considered when determining the fee to be charged to a third party for handling its Outside Substances. If there is a problem with the cost differential, two alternatives to consider would be a denial of entry to the Production Facility or a renegotiation of the financial arrangement under which access is provided. The latter could be a renegotiation of the fee to be charged to a third party under Clause 14.04 or the negotiation of a fee type arrangement with the Party using surplus capacity to handle the applicable Outside Substances.

Clause 14.05: In essence, Operating Costs are allocated on the basis of the throughput of Petroleum Substances and Outside Substances. The dispute resolution mechanism in Article 21.00 will apply under Clause 14.08 if there is a disagreement about the allocation.

The Operator will initially allocate the costs monthly on an estimated basis (often based on the previous year's share of throughput) and then make any required adjustment within 180 days after the end of the year based on actual costs and throughput volumes. This is subject to any special allocation of Operating Costs under Subclause 14.04D. Adjustments would be minimal if the ownership of volumes throughout the year were consistent.

Clause 14.06: This provision provides the basis for allocating products generated from the processing or treatment of hydrocarbon substances using a Production Facility. Clause 14.04 requires the Operator to structure its agreements with each third party fee user to include provisions consistent with the principles in Paragraphs 14.03(a) and (b) and Clauses 14.05, 14.06 and 14.07.

Clause 14.07: This provision reflects standard industry practice for the allocation of shrinkage, production losses and facility fuel in minor facilities.

Clause 14.08: The dispute resolution process in Article 21.00 can apply If the owners of a minor facility cannot resolve a dispute respecting: (a) the capacity or surplus capacity of a Production Facility; (b) a usage fee under Subclause 10.08F or Clause 10.13 or 14.04; (c) the allocation of Operating Costs; (d) a significant variation in the composition of inlet streams of Petroleum Substances and Outside Substances; or (e) the allocation of products or losses. Binding arbitration is a possible outcome.

Clause 15.01: Provisions like this have often been used in farmout agreements and joint operating agreements, and a similar provision was introduced as Clause 801 of the 1990 document. A Party that has encumbered its interest by burdens in addition to the lessor royalty and any encumbrances borne for the Joint Account is to free the interest from them if the interest is surrendered, forfeited or subject to an Article 9.00 or 10.00 cost recovery. If it fails to do so, it will have liability and indemnification obligations for any resultant Losses and Liabilities of the Parties.

The only way that an encumbered Party can free the interest from the burden is to structure the contract creating the encumbrance accordingly. A Party that encumbers its interest must structure its contract so that the encumbrance does not have an adverse impact on its co-venturers if the surrender, forfeiture or cost recovery provisions subsequently apply. This is particularly critical when granting ORRs to employees and consultants or when farming in on only one Working Interest owner and then becoming party to the applicable joint operating agreement in place of the farmor.

Clause 15.02: i) The purpose of this Clause is not to encourage the creation or recognition of encumbrances. It is to distinguish between encumbrances that have a special treatment under the document and those which do not. Any additional encumbrance that is not created in the Agreement only falls within the scope of Clause 15.02 if the Parties voluntarily agree to provide it with a special status in the Agreement. Many Parties will not wish to become involved in a contract that does not apply to its interest. They will be extremely reluctant to accept any special treatment for additional encumbrances that are not created in the Agreement.

ii) Encumbrances that are not borne for the Joint Account may be created under the provisions of the Agreement, such as a farmor's ORR, or may be acknowledged as being one that attaches to the Working Interest therein. Any such encumbrance will be an exception to the general rule in Clause 15.01. (See also Subclause 10.07F for the handling of this type of encumbrance in a cost recovery scenario.)

iii) Users should always check the Head Agreement to confirm if there is any special treatment of an encumbrance. Although an encumbrance may be created under the Head Agreement, it may also include special provisions overriding this Clause.

iv) An exception against non-arm's length encumbrances has not been included. The Parties would most reluctantly agree to accept a non-arm's length encumbrance that would run with the interest under Clause 15.02. However, the inclusion of a specific exception for non-arm's length encumbrances could operate to extinguish a legitimate encumbrance that is subsequently purchased by a Party.

v) A Party may occasionally find itself presented with a joint operating agreement for a Crown sale area of mutual interest acquisition where the other Party is insistent that an ORR applicable to its interest is recognized (e.g., "geologist ORR"). The simplest response to this if a provision comparable to Clause 8.07 of the CAPL Farmout & Royalty Procedure applies is that a separate joint operating agreement is not required. That type of provision states that the Operating Procedure to the Agreement will apply to the acquisition, such that the ORR that applies to that Party's interest would not be recognized for the purposes of Clause 15.02.

Clause 16.01: i) An overview of the general law respecting Force Majeure was presented in Atcor Ltd. v. Continental Energy Marketing Ltd., [1994] A.J. No. 715 (Alta. Q.B.). The case pertained to a marketing agreement in which a party could rely on the force majeure provision if it failed to perform any of its obligations and the failure was "in consequence" of force majeure. In essence, there were curtailments of transportation capacity by a third party and the seller chose to allocate its reduced volumes to other purchasers, rather than to Continental. The Court determined that the curtailments were an event of force majeure that could not have been avoided by the exercise of due diligence. After reviewing the two major types of force majeure provisions, the Court determined that the provision in that agreement did not require Atcor to mitigate the impact of the force majeure on the performance of its obligations under the agreement by, for example, purchasing other gas in the market for delivery to Continental.

The provision historically used in the CAPL Operating Procedure, on the other hand, is an "unable to prevent" provision that would require the Party claiming Force Majeure to attempt to mitigate the impact of the Force Majeure on an ongoing basis.

ii) This Clause applies to performance of all applicable obligations, including those for which there is a specified period for Commencement. While the individual provisions do not state that they are subject to this Article, the effect of the "notwithstanding" reference is that they are.

iii) A Force Majeure suspends the performance of the affected obligations for the period that it prevents performance and for such additional time as the Party may reasonably require to commence to fulfil them. The affected Party cannot practically be expected to begin to fulfil obligations the moment the Force Majeure is remedied, as equipment and personnel may have to be mobilized on short notice.

Subclause 17.01A: i) Only incentives that accrue to the Operation (such as the former Alberta EDAPs or DICs) are shared by the participants under this Clause. The Operator for the Operation is to apply for the applicable incentives or royalty exemptions in the manner prescribed by the Regulations. "Incentives" that accrue to all or only some participants individually because of their unique corporate attributes (such as the former ARTCs, APIPs and CEDIPs) are not shared, as they accrue to the "personality" of the participant, not to the particular Operation.

ii) The most typical incentive accruing to an Operation would be a temporary royalty exemption. A prudent Operator would be aware of any such program because of the synergy with production reporting and accounting.

iii) The reference to differences in cost bases is included because of the current shale gas royalty regime in British Columbia and the royalty regime in the Northwest Territories and the probability that the document will be used as a basis for some northern agreements.

Subclause 17.01B: i) This Subclause was introduced in the 2007 document because of changes in the Alberta and B.C. Regulations allowing the "grouping" of multiple documents of title thereunder. If an Operation entitles the Parties to retain P&NG rights for a further period, those entitlements will first be applied to the Joint Lands. If entitlements remain that cannot be used for the Joint Lands, the Parties will consult to determine how they will be used. Insofar as they are unable to agree on their use, each Party may use its Participating Interest share of the remaining entitlements for such other P&NG rights as it may select, subject to any restrictions under the Regulations or in the Head Agreement. (See also Subclause 3.10C.)

To illustrate, assume that: (a) A and B have participated on a 50-50 basis in a well that would entitle them to the retention of 12 sections under the Regulations when there are only six sections of Joint Lands that could use those entitlements; (b) A (50%) and B (15%) hold six sections of other P&NG rights that could use those entitlements under another agreement; and (c) B holds two other sections of 100% lands that could also use those entitlements. Unless otherwise agreed by A and B, the first six sections of entitlement would be applied to the Joint Lands, such that each has an entitlement to three remaining sections. Assuming that B's greater priority was the retention of its 100% P&NG rights, B could apply two sections of its entitlement to its 100% P&NG rights and the remaining section to its minor interest J.V. section.

Notwithstanding the specified allocations, the Parties will often use this Subclause as a basis for a negotiated allocation of the entitlements. This could see the Party with surplus entitlements informally "owed" some entitlements at a subsequent date in an unspecified area.

ii) A "farmee" that wishes greater discretion to use grouping or validation rights to optimize its retention of lands should address its expectations on this issue during the initial negotiations, and document the outcome in the Head Agreement.

Clause 18.01: i) A review of the cases about breach of confidence is included in Part II of the Addendum at the end of the annotations. Parties disclosing confidential information in commercial negotiations should enter into an appropriate confidentiality agreement before any such disclosure. The legal and equitable remedies normally available for a breach of this Article are not impacted by the restrictions on Extraordinary Damages in Clause 4.04. Damages under this Article are excluded from that definition, as it is inherent that they cannot be direct damages.

ii) A Party may use information for its own benefit and account. This statement was initially included in the 1990 document to address any argument of constructive trust if a Party used joint information to acquire adjacent lands for its own account when there was no area of mutual interest obligation. There would only be a slight chance that the doctrine of constructive trust would be imposed in such circumstances when the agreement is among knowledgeable Parties. However, the reference may be relevant if one or more of the Parties has little expertise, such as a Party which is a passive investor. The reference is consistent with Subclause 1.05C.

iii) The Parties make two different types of disclosures under the Regulations. One is a mandatory disclosure, such as the disclosure of prescribed types of drilling information. The other is a voluntary disclosure made to attempt to optimize the retention of lands, whether they are Joint Lands or other lands held by a Party under other documents of title. A Party's ability to disclose information under the Regulations for its other lands falls within the scope of the first sentence of the Clause, subject to the requirement not to disclose the information to other third parties. (The submission of information may also be a requirement under the applicable Title Documents, such as a Prairie Sky/Encana/PanCanadian freehold lease.)

iv) Stock exchange requirements generally require publicly traded companies to make timely, full, true and plain disclosure about developments that would reasonably be expected to affect the market value of a company's stock significantly. The foundations of this requirement are the objectives to provide all who invest in listed securities with equal access to information that may affect their investment decisions and to minimize the likelihood that those with preferential access to undisclosed information could profit from that knowledge.

For this purpose, the TSX rules provide that "Material information consists of both material facts and material changes relating to the business and affairs of a listed company." It is largely left to the judgment of a listed company to determine what information is material and must be disclosed. However, the TSX may also require a public announcement if trading volumes are anomalous or rumours or speculation exist.

TSX requirements provide that disclosure is generally required upon information becoming known to management or, if known, upon the information becoming material. However, the TSX may allow the disclosure to be deferred if early disclosure could compromise the company's interests and the potential harm caused to the company and its investors by the disclosure outweighs the consequences of delay (e.g., premature disclosure of an intention to attempt to purchase an asset potentially increasing the price or disclosure of confidential corporate information that would benefit competitors). The TSX rules stipulate, though, that a company must retain strict confidentiality if disclosure is deferred, and immediate disclosure is required if there is any leak of the information.

The announcements must be factual and balanced, "neither over-emphasizing favourable news nor under-emphasizing unfavourable news". There must be enough information contained in the announcement to allow investors to make informed decisions about their investments.

The test of whether a transaction is a "material change" is a subjective one, as a transaction that is "material" for one company would not necessarily be "material" to another. As noted in the TSX Policy Statement on Timely Disclosure, "The materiality of information varies from one company to another according to the size of its profits, assets and capitalization, the nature of its operations and many other factors. An event that is "significant" or "major" in the context of a smaller company's business and affairs is often not material to a large company. The company itself is in the best position to apply the definition of material information to its own unique circumstances. The Exchange recognizes that decisions on disclosure require careful subjective judgments, and encourages listed companies to consult Market Surveillance when in doubt as to whether disclosure should be made." The TSX Venture Exchange has similar requirements. Additional information for both can be found on the TSX web page.

v) Information included in Annual Reports and other presentations made to shareholders and the investment community typically extends beyond that required to be disclosed under securities laws. The disclosing Party has an obligation not to disclose information from the Agreement that could damage the interest of the other Parties, and Article 19.00 would apply to those public announcements. To illustrate, Joint Lands held by a third party agent should not be identified on a map of the project area in an annual report if this is commercially sensitive information at the time.

vi) It is not feasible to have a separate confidentiality agreement for each disclosure of information to employees, officers and Affiliates. However, the disclosing Party remains liable for any Losses and Liabilities suffered by the Parties as a result of their disclosure of confidential information.

vii) Paragraph (d) provides greater flexibility to disclose information than in the pre-2007 documents. This reflects the reality of the marketplace. A Party may disclose data not subject to a Clause 18.02 obligation on a confidential basis to its prospective assignees and also in the context of any *bona fide* merger or amalgamation discussions. The latter reflects the document principle that corporate type transactions should not be frustrated, and is consistent with the exemption from rights of first refusal for those types of transactions (Paragraph 24.02(b)).

The Paragraph also recognizes that it is a well accepted industry practice for a Party to "show" seismic data at its offices or in its data room, on a confidential basis, to encourage a potential assignee to enter into an agreement (i.e., a farmin for the evaluation of the Joint Lands). Subject to the release process in Clause 18.03, this does not provide the disclosing Party with the right to provide the prospective assignee with a copy of the data. The ability to "show" the data to a potential assignee is contingent on a Party not being prohibited from that type of disclosure under the agreement through which the geophysical data were acquired (e.g., licencing agreement with unusual restrictions).

viii) The reference to legal counsel and financial and professional advisors in Paragraph (e) recognizes that they receive information in practice.

ix) Paragraph (f) was introduced in the 2007 document, and applies to information required to be disclosed under legal or administrative proceedings. <u>Murphy Oil Co. Ltd.</u> v. <u>Predator Corp.</u>, [2002] A.J. No. 647 (Alta. Q.B.) is relevant to this Paragraph. A Court may set aside confidentiality agreements. This reflects the policy view that "the search for the truth" serves a greater public need than freedom of contract. This type of order enables a witness to testify about matters subject to the confidentiality agreement if the witness is willing to do so.

x) Paragraph 1801(e) of the 1990 document allowed disclosure to "Scout Check". It has been deleted because of the decline in membership.

xi) The disclosure of general information, such as total depth or status, does not enable one to argue that well data is not confidential because that particular information is in the public domain.

xii) Parties will often include confidentiality provisions in their agreements with many of the service providers contemplated in Paragraph (e). A specific obligation was not included because of the general duty on each Party in the introduction to Clause 18.01.

Clause 18.02: i) A Party may voluntarily offer to disclose information for the benefit of Operations. Assuming the other Parties are willing to receive it, this Clause reinforces the responsibility of the recipients to keep that information confidential. This was introduced in the 2007 document, and will be of greatest relevance if the contemplated Operations involve the use of complex technology.

ii) A Party prepared to disclose sensitive proprietary information should make the disclosure through a confidentiality or licencing agreement at the time. The better practice would be to offer the disclosure by notice, so the information proposed for disclosure is clear.

Clause 18.03: i) This provision addresses the release of confidential information to third parties for consideration. The Party that wishes to release the information is required to obtain the consent of the other Parties with a proprietary interest in the information and to share the consideration for the disclosure with them. As third party contributions to Operations would generally be in the context of bottomhole contributions or drilling options, the inclusion of this Clause in the 1990 document allowed the deletion of Subclause 1701(a) and Clause 1702 of the 1981 document.

ii) Participants in an Independent Operation maintain all proprietary rights to that information, and are free to disclose it without the consent of a Non-Participating Party, notwithstanding Clause 18.01 and the possible deferred distribution of that information to a Non-Participating Party under Clause 10.19. However, disclosure by the Participating Parties can affect the cost recovery account under Subclause 10.07H. Providing a Non-Participating Party with broader rights to participate in data disclosure decisions and the receipt of trade data would enable a Non-Participating Party to frustrate data disclosures and to obtain technical insights that could compromise the competitive position of the Participating Parties.

iii) A farmee that conducts a geophysical program under an optional earning arrangement would typically retain all ownership rights to that data under the Head Agreement for the purpose of this Clause.

iv) The disclosure of information under this Clause will often be in the context of an exchange of information that involves the execution of a confidentiality or licencing agreement. It might be executed by all relevant Parties or only by the Operator on behalf of those Parties. The better practice for the latter is for the Operator to include with its notice a request for authorization to execute that agreement on behalf of the Parties, and the Operator might include a copy of the proposed agreement if one is available at the time of the notice. Since the Operator will have executed any such agreement on behalf of the Parties, it should include a copy of the executed agreement with the provision of the information in due course, so that the Parties are aware of their rights and obligations.

Clause 18.05: i) A Party that surrenders or forfeits its entire interest is not relieved of its obligations to maintain information confidential until it is in the public domain. This differs from the traditional pre-1990 provision, which linked the confidentiality obligation to the term of the Operating Procedure. Assuming that A and B held lands and that A surrendered its entire interest to B, that type of provision might literally be interpreted to release A from any obligation to maintain information confidential.

ii) Parties need to be aware of the potential for seismic information obtained under this Agreement to be assigned inadvertently under a notice of assignment in the absence of other arrangements to the contrary under which seismic information is managed. Even in the absence of any other agreement governing the management and licencing of seismic data, disclosure may be governed by practice standards established by the Canadian Society of Exploration Geophysicists. (See also Clause 18.07, which was introduced in the 2015 document.)

Clause 18.06: i) This Clause was introduced in the 2007 document. It is premised on the assumption that relatively open discussions will often be occurring between the Parties' representatives, particularly for technically complex or high-cost projects. Notwithstanding any sharing of information that may occur, each Party is ultimately responsible for its own evaluation of information and proposed Operations. The one exception to this general rule is for fraud or deceit, such as an intentional distribution of false or selective information in the hope that the other Parties would rely on it.

This Clause is similar to the disclaimer typically included in industry's P&S Agreements. (See, for example, Subclause 6.05B of the 2000 CAPL Property Transfer Procedure and the associated annotations.)

ii) <u>Opron Construction Co.</u> v. <u>Alberta</u>, [1994] A.J. No 224 (Alta. Q.B.) reviewed the law respecting disclosure and reliance on information in the context of a tendering scenario in the construction industry and a claim of selective disclosure of information. The case found that a finding of fraud or deceit requires three elements: (a) the applicable party to know that a statement or information is false or for it to be reckless as to its truth or falsehood; (b) an intention to induce reliance; and (c) reliance on the information by the injured party. The Court also confirmed that a limitation clause cannot excuse fraudulent misrepresentation.

Clause 18.07: This Clause was introduced in the 2015 document. The conduct of a geophysical program is an Operation to which the Operating Procedure can inherently apply. However, the Operating Procedure does not suitably address the issues associated with the ongoing management of that data, protocols for licensing/release and transfers of ownership. As a consequence, the owners of geophysical data might enter into a separate agreement addressing those types of issues that will supersede the Operating Procedure with respect to the subject matter of that agreement.

Clause 19.01: i) This Clause was introduced in the 2007 document. It reflects increased sensitivity to public releases of information about activities conducted hereunder. This is particularly important for high-risk, high-reward activities or other areas in which there are competitive sensitivities.

ii) Subclause A requires the Party proposing the disclosure to provide a draft of the proposed release to the other Parties at least two Business Days before the release. The release is then subject to the approval of the other Parties, which approval may not be unreasonably withheld. Failure to respond within that two-day period is deemed approval. Limited exceptions to this general approval mechanism are included in Subclauses B and C.

If the agreement is one that will use complex technology or generate significant scientific information, the Parties may wish to consider a proviso whereby the notice period is extended to 10 Business Days for any disclosure that is primarily a paper or presentation of a scientific nature.

iii) All releases made on behalf of the Parties collectively are to be issued by the Operator under Subclause B. The Operator may issue such a release without prior approval of the other Parties insofar as prior approval is not feasible in an emergency. However, the Operator is required to work with the Parties in an emergency situation as feasible under Subclause 3.05B. Except for the emergency exception, all other releases by the Operator in its capacity as Operator will be through the notification process in Subclause A.

iv) Any Party may issue a release on its own behalf under Subclause C. Prior approval will not be required insofar only as the release is required to comply with securities laws applicable to the Party with respect to material events or material changes, as described in detail in annotation (iv) on Clause 18.01. Other releases being made by a Party, including releases of property specific information in an Annual Report, are subject to the notification process in Subclause A. Although prior distribution to the other Parties is not required for releases required by securities laws, it is the better practice to provide the other Parties with a draft on short notice for their information and feedback. This is a particularly relevant consideration if other Parties are publicly traded and the release would be material to their business.

Clause 20.01: This Clause is primarily designed for third party actions against the Parties collectively. It does not prevent a Party from starting an action against another Party, such as a suit alleging the Operator's Gross Negligence or Wilful Misconduct. It is inherent in the last sentence that no Party could unilaterally pursue an individual course of action respecting a Joint Account claim that would compromise the Parties collectively.

Article 21.00-General Structure: This Article was created as one of the outputs of the "Company to Company Dispute Resolution Task Force". This was an industry driven initiative to improve the dispute resolution processes in the oil and gas industry. Additional information about this Task Force and its report "Let's Talk" can be found at wwwc2cadr.org. These annotations focus largely on some of the philosophies in the "C2C Project".

Article 21.00-Optionality: This Article has been structured as an optional Article, so that users have the flexibility not to apply the Article to their Agreement. The structure is unusual, though, as arbitration using the *Arbitration Act* (Alberta) is to be used to resolve several of the disputes listed in Clause 21.03, even if the Article is not selected (the items in Paragraphs 21.03(c)-(j)). This mechanism is largely designed to place the Parties in a similar position to the outcomes under the 1990 document for the strategically significant items in Paragraphs 21.03(f), (i) and (j), as well as the similar fact-based determinations in the other included Paragraphs. However, the additional processes in Clause 21.03 that flesh out the manner in which an arbitration is conducted (i.e., the use of the "National Arbitration Rules") do not apply to those arbitration proceedings.

Notwithstanding that the additional Clause 21.03 processes may not apply, Parties involved in an arbitration proceeding should supplement the *Arbitration Act* with the use of some recognized form of "arbitration rules" for the reasons noted in the annotations on Clause 21.03.

Subclause 21.01A: i) The foundation of Article 21.00 is a strong preference for Parties to resolve their own disputes through negotiation. The supplementary processes provide a road map if negotiations are not initially successful, while reinforcing negotiation as the preferred course.

Successful negotiations are focused on the problem (rather than the people), and will typically see the right people communicating in the right way at the right time. Experience has shown that face to face dialogue early in the negotiating process is particularly beneficial relative to the alternatives of phone conversations, letters or e-mails. Conversely, negotiations are more challenging and much more likely to escalate into a prolonged, adversarial process if the tone is negative, if one of the Parties refuses to engage in discussions or if either of the Parties is unwilling to listen to an alternative perspective or to share information that would provide additional insights about a Party's concerns or expectations.

This emphasis on negotiations also recognizes that the vast majority of disputes that escalate to litigation are eventually resolved through negotiation prior to or at trial. Given that the typical dispute can be resolved at a business level if there is a mutual will to do so and that the Parties are usually motivated to develop that mutual will eventually anyway, why not fully explore negotiation approaches sooner, rather than later?

ii) One step that a Party might consider relatively early in a negotiation that is not proceeding well is the use of an outside neutral facilitator. This can help focus (or refocus) the negotiations by: (a) framing clearly the issues that are in dispute; (b) objectively summarizing the Parties' respective perspectives; and (c) facilitating a discussion of potential alternatives. The use of a facilitator at this stage can be relatively inexpensive, and can provide a platform for the Parties to resolve their dispute much more easily than might otherwise be the case. Outside facilitation can be particularly helpful if the difficulties in the current negotiations are a symptom of broader ongoing problems between the Parties.

iii) Another approach that might be helpful in refocusing a stalled negotiation is a letter to the other negotiator that outlines similar information to that contemplated in a notice issued under Subclause 21.02A.

iv) The Parties should also consider the process within which the dispute is most appropriately advanced before negotiations become adversarial and positional. While further negotiation may be attractive, a broader range of options should often be considered. Litigation may, in fact, sometimes be the most appropriate option. There will also be situations in which it is beneficial to engage a neutral expert for one of the initial meetings to help the Parties (and their legal advisors) understand more fully the options to address their dispute. Although there is no requirement to involve a neutral expert at this stage, the Parties are encouraged to consider in advance if this is a path that may be attractive for their dispute.

One simple solution that is proving effective in both regulatory and non-regulatory dispute resolution systems is the Preliminary ADR meeting ("PADR") (possibly also referred to as a Situation Assessment Meeting or "SAM"). This meeting is an opportunity for Parties in conflict to discuss the dynamics of their dispute and jointly design a dispute resolution process appropriate to their unique situation. In essence, this enables the Parties to build a road map for resolution of their dispute, while ensuring that they do not harm or compromise their litigation steps.

These meetings are flexible, and generally: (a) are facilitated by a neutral dispute resolution expert; (b) deal with process issues, not substantive ones; (c) identify the necessary Parties and address issues of authority; (d) address planning, preparation and logistics for the process; (e) enable the custom design of the appropriate dispute resolution tool (i.e., mediation, arbitration, litigation) and, if applicable, the selection of a neutral facilitator; and (f) provide the best opportunity to make an informed decision about continued participation in a future dispute resolution process.

Experience with this process in a regulatory context has been positive. It's a safe and simple first step in stressful and conflicted situations. Most Parties agree to an invitation to a PADR/SAM meeting, as they have "nothing to lose". Most Parties would more fully commit to a dispute resolution process they have helped to design, and this has historically resulted in a higher settlement rate before litigation. The Parties identify roadblocks and preparation issues, and plan for these effectively, enhancing the success of the process. The Parties bring decision-makers to the meeting, which is set for a specific duration to maximize results. An informed "no" and a decision to proceed with litigation is a perfectly acceptable outcome.

Subclause 21.01B: A Party can "fast track" resolution of an item identified in Clause 21.03 by referring the matter directly to arbitration. However, the Parties should consider the potential benefits of using the other process steps if it is not critical to seek immediate resolution. A disposing Party facing a challenge of a ROFR value would typically negotiate a deferral of the closing date or a closing in escrow with its assignee. Rejection of a mediation request under Clause 21.02 also positions a Party to move to arbitration.

Clause 21.02: i) This provision reflects the increased use of mediation to resolve disputes. Mediation cannot be successful if the Parties are unwilling to explore alternative ways to resolve the dispute, so any Party may terminate the mediation process by notice to the other Parties.

ii) While not stated in the Clause, a Party receiving a mediation request will often choose to respond in writing to the information in the notice.

iii) Parties considering mediation are motivated to agree on a mediator in practice. When choosing a mediator, it is important to consider the type of mediator to use for the mediation. Do the Parties require one who tries to lead them to a resolution that the mediator believes is appropriate based on the mediator's experience (an "evaluative mediator") or do they require one who tries to facilitate the discussions to enable them to develop a resolution that they believe is appropriate (a "facilitative mediator")? If they are unable to agree on the selection of a mediator, they might consider obtaining a list of potential mediators from groups such as the ADR Institute of Alberta and the ADR Institute of Canada Inc., where the latter is also willing to select one for them. (More information about the ADR Institute of Canada Inc. is found on its website at www.adrcanada.ca, and more information about the ADR Institute of Alberta is found at its website at www.adralberta.com.)

iv) A mediator and the Parties will jointly determine the process to be used for the mediation, including any confidentiality requirements. The Parties might consider adopting the National Mediation Rules of the ADR Institute of Canada, Inc. or any similar rules.

v) This is an early mediation provision. It reflects a greatly increased emphasis on mediation in the judicial system.

vi) A mediator will sometimes choose to terminate a mediation because, for example, of an impasse in discussions or bad faith.

vii) Costs and expenses of the mediation are to be shared equally by the affected Parties, unless they agree on a different arrangement at the time. This approach is consistent with the handling of those costs in the Dispute Resolution Appendix of the 1996 and 1999 PJVA CO&O Agreements.

Clause 21.03: i) The focus in Clauses 21.01 and 21.02 is an "interest-based process" in which Parties attempt to resolve their dispute in a way that meets their mutual needs from a broad range of potential alternatives. Failure to resolve a dispute under those Clauses shifts the focus to a "rights-based process" if formal proceedings are commenced through arbitration or litigation. The "rights-based" reference is used because of the potential involvement of a neutral third party to adjudicate the dispute and provide an answer based on the respective entitlements under the Agreement.

ii) Except for civil proceedings permitted under Clause 21.04, a Party that wishes to pursue an issue formally after a failed mediation is required to use arbitration if the dispute is one that pertains only to one or more of what is generally a specified list of fact-based items. The Parties are also free to agree to refer any other dispute to arbitration instead of pursuing judicial proceedings.

Many users are very reluctant to use arbitration. This is largely because of a concern about the possibility of an unpredictable outcome. As a consequence, the references to arbitration in this Clause might initially be of concern to some users because of a possible perception that the provision is designed to encourage the use of arbitration to resolve disputes.

The inclusion of arbitration references, in fact, is designed, firstly, to encourage the Party in the "power position" to listen more carefully to the concerns of another Party than would otherwise be the case if litigation were the only remedy and, secondly, to encourage all Parties to resolve the issue through negotiation without actually resorting to arbitration and the possibility of an unfavourable outcome outside its control.

When considering the use of arbitration as a dispute resolution vehicle in this Clause, it is important to note for context that the CAPL Operating Procedure has dictated the use of arbitration for the resolution of strategically critical disputes on ROFR values (since the 1971 document), title preserving well issues (since the 1990 document) and many Production Facility issues (since the 1990 document) without apparent issues or any apparent proliferation of arbitration proceedings.

iii) Unresolved audit exceptions have been included as an optional item with a negotiated value threshold. As audit exceptions often require some interpretation of the Accounting Procedure, this approach provides Parties with greater control over the degree to which arbitration should be the ultimate dispute resolution vehicle for this type of dispute.

iv) Unless otherwise agreed, a single arbitrator will conduct an arbitration in Calgary under the "National Arbitration Rules" of the ADR Institute of Canada Inc. (or any replacement for those rules). The Institute results from the merger of The Canadian Foundation for Dispute Resolution and the Arbitration and Mediation Institute of Canada Inc., and the CFDR remains its wholly owned subsidiary. The rules are substantially of a procedural nature. They supplement or make substitution for provisions of the Arbitration Act for the applicable jurisdiction (i.e., Alberta, in the absence of modification to this document). The handling of costs and appeals thereunder are generally on the same basis as provided in the applicable Arbitration Act.

Clause 21.04: i) Provided that the Regulations permit an extension, limitation periods are suspended from a notice to mediate until 45 days after termination of the mediation (including the deemed termination in the first sentence of Subclause 21.02B), or such other date as the applicable Parties may agree, with a similar outcome for arbitration. Notwithstanding this provision, the Parties' lawyers will frequently choose to supplement it with separate documentation in the context of their particular dispute, particularly if the issue is significant and mediation is attempted close to expiry of the applicable limitation period. Parties intending to rely on the extension of the limitation period on the basis contemplated by this Clause should obtain legal advice at the time to confirm that their rights are preserved under the applicable Regulations.

ii) The timing is linked to the mediation and arbitration processes, rather than the negotiation process. There are two reasons for this approach. The first is that the documentation for the negotiation process will typically be quite loose in practice. The second is to provide reinforcement for Parties to use negotiations to attempt to resolve their disputes much earlier than has often historically been the case.

iii) A review of the law about injunctive relief is found in Gulf Canada Resources Ltd. v. Pembina Resources Ltd. (1994), 152 A.R. 74 (Alta. Q.B.). It was a dispute about the appointment of a new operator under a pre-CAPL Operating Procedure. The Court found that the plaintiff did not demonstrate irreparable harm entitling it to an injunction, such that it could adequately be compensated in damages if it suffered losses. The law in this area was also reviewed in Constellation Oil & Gas Ltd. v. Sunoma Energy Corp., [1999] A.J. No. 1202 (Alta. Q.B.), ExxonMobil Canada Energy v. Novagas Canada Ltd., [2002] A.J. No. 775 (Alta. Q.B.) and AltaGas Services Inc. v. BelAir Energy Corp., [2003] A.J. No.1127 (Alta. Q.B.).

Subclause 22.01A: i) Paragraph (a) provides that a notice may be served on a Party during its normal business hours on any normal working day. Service after normal business hours is treated as receipt on the next Business Day. If a Party is closed on a particular day by its own choice (e.g., a scheduled Friday off), the Party will still be deemed to have received the notice on that day, assuming it has a representative to receive it.

ii) It is possible for the Parties to have different response dates because of different delivery times. However, the issuing Party would typically use the latest date as the response date for all Parties in practice.

iii) Paragraph (b) does not require the addressee to acknowledge receipt for that notice to be effective. It is sufficient if the Party serving notice can demonstrate that it was sent. The Party serving notice should not be required to assume the risk that the addressee's personnel do not handle the notice properly or that its equipment is not functioning properly. Otherwise, that Party would never know if its notice was effective. In the unlikely event there is actually a problem with receipt, the business considerations are such that the matter would typically be resolved to the addressee's satisfaction once the problem is identified. The onus, however, is on the addressee to satisfy the other Parties of the legitimacy of its request.

iv) Service of notice by facsimile under Paragraph (b) is contingent upon the addressee having included its fax number in its address for service.

v) The reference "other electronic medium" has been included to accommodate the issuance of notices by e-mail if the Parties choose to include an e-mail address in their respective addresses for service. A notice delivered by e-mail will not be a valid notice if a Party's address for service does not include its e-mail address. A Party should only consider including an e-mail address in its address for service if it has processes in place to ensure that e-mail is checked on a regular basis, such that it is not at risk because of vacation, business trips, etc. The content in the Paragraph in this area is based on the *Electronic Transaction Act* (Alberta).

vi) A notice must be served under Paragraph (a) or (b) if the applicable notice period is 48 hours or less. However, a telephone notice may be used for the 24-hour Casing Point election, to reflect typical industry practice.

vii) It is the better practice to serve important notices (i.e., issuance of a response to an Operation Notice or ROFR notice) under Paragraph (a). This expedites delivery and provides a tracking mechanism if the issuance of the applicable notice or the timing of its receipt is challenged.

viii) Remember that Paragraph 1.02(k) addresses the manner in which to count days and Business Days for notices served under the document. (A comparable provision was introduced in Clause 103 of the 1990 document.) That Paragraph generally states that the first day of the response period is the day following receipt and that expiry of the response period falling on a weekend or statutory holiday extends it to the next Business Day.

Subclause 22.01B: i) Technology exists that enables subscribing parties to issue, respond to and track AFEs and Operation Notices through a fee for use electronic delivery system, something very different than a normal e-mail. This Subclause was introduced in the 2015 document to facilitate, as among only Parties using that service, the ability to use that service for the management of AFEs and Operation Notices being issued under the Operating Procedure. There is nothing in this Subclause, though, that requires a Party that does not subscribe to any such service to subscribe to it just because some other Parties are subscribers.

The inclusion of this Subclause allows the subscribing Parties to use that service for delivery of communications respecting AFEs and Operation Notices to other subscribing Parties. In essence, this recognizes that they are basically waiving, as among themselves only, the application of certain procedural aspects of the Operating Procedure.

However, this Subclause requires them to follow the prescribed notification processes in Subclause 22.01A with respect to Parties that do not use that service, such that the rights of the non-subscribing Parties (and the associated obligations to them) are not altered in any way as a result of the inclusion of this Subclause. This would require any such subscribing Party to use two parallel processes for the issuance and response to any such AFE or Operation Notice if fewer than all Parties subscribed to that delivery service.

As regards Parties that subscribe to any such delivery system, this Subclause has the effect of ensuring that notices are not invalidated for users of the system that follow the protocols within the system design and the obligations that process users undertake to each other under the terms of their subscription agreements.

These changes offer greater waiting functionality for users that choose to use that type of technology. These changes will be particularly beneficial if that technology becomes widely used in due course by a critical mass of industry.

ii) Any such delivery system is well suited to the handling of AFEs issued for information or approval under Clause 3.01 or Article 7.00 and Operation Notices with the normal 30-day election period. As contemplated by Paragraph (b), Parties that subscribe to any such delivery service may still prefer to issue any Operation Notice subject to a 48-hour election period or the 3.2km election deferral mechanism under Subclause 10.02F because of the fact specific nature of those Operation Notices.

Clause 22.02: i) Each Party is to notify the other Parties of any changed address for service in a timely manner. This is implicit in the provision, so has been expressly included as a reminder to administrative personnel. Prompt notification of a changed address for service minimizes the risk that time sensitive notices will be misdirected or that a Party could become a delinquent Party. The latter is a particular risk for smaller companies that are not well known, particularly if they are located outside of Calgary or are operated out of a private home.

ii) Home Oil Co. Ltd. v. Northridge Exploration Ltd., [1998] A.J. No. 519 (Alta. Q.B.) pertained to a situation in which Home exercised its ROFR on a property by sending the election to Northridge's former address. Although Home had updated Northridge's address in its internal records after receipt of a general notice, the election letter was sent to the old address that was on the Northridge letterhead used for the ROFR notice. The Court found as a fact that Northridge had intentionally been using its old letterhead after a merger as a cost saving measure and that Home was entitled to send its ROFR election to that address. One of the comments in *obiter dicta* was the Court's question of whether a general change of address circular delivered to industry without reference to specific agreements could be an effective means to change address.

iii) Parties have sometimes purported to use solely a post office box address for service of notices in circumstances in which the Party clearly had an office at a readily accessible location from which it was conducting business on a sustained basis. This Clause was modified as of the 2015 document to prohibit the selection of any such address for service because of the negative impact this would have on the normal course of business communication (i.e., delivery of notice to a Party's office by courier). One could also potentially argue that the Further Assurances Clause of all versions of the document would preclude the purported selection of any such address. That being said, there will be circumstances in which there will be exceptions to this handling, such as when dealing with smaller players operating from a private residence or in a rural area.

Clause 23.01: A Party does not become a delinquent Party if it only fails to settle its accounts hereunder. The Operator already has potential legal remedies to address that problem under the default processes in Clauses 5.05 and 5.06. (See also Clause 23.04.) Similarly, an oversight in providing the other Parties with a new address would not seem to be sufficient if the Operator can easily determine that Party's new address by phoning its old office number or obtaining a new phone number from directory assistance.

Clause 23.02: i) The option of paying funds into Court was not included. The Operator requires the right to deduct that Party's share of costs incurred for the Joint Account in a simple and timely manner. If other amounts were owing, the Clause 5.05 default process could be used.

ii) The burden of managing this issue has been reduced. The Operator may commingle the net funds with its other funds, and any ultimate adjustment of accounts is without interest because of the incremental administrative burden in accounting for the delinquent Party's interest.

iii) The delinquent Party is deemed not to participate in any proposed Operation, but remains responsible for all costs incurred for the Joint Account that do not require prior approval under Subclause 3.01B (e.g., emergency scenario, payment of rentals under Clause 3.10, etc.). It will be deemed to have elected to join in all farmouts, surrenders, Abandonments, etc. effected by the Operator on a *bona fide* basis for its own account.

iv) The Operator is appointed as the delinquent Party's attorney for the handling of documents required to be executed by the delinquent Party as a result of this Article, with an indemnification from the delinquent Party.

v) The rights, benefits, obligations and liabilities of a delinquent Party will be assigned proportionately to the other non-delinquent Parties (including the Operator) if it does not restore its status within 24 months after issuance of the Clause 23.01 notice. This was introduced in the 2007 document. While this will not necessarily result in the assumption of net liabilities by the Non-Operators, this could be the case. This result is consistent with the philosophy in Clause 5.06, which recognizes that the Operator should not bear this type of cost for its sole account. (See also annotation (viii) on Clause 12.01 respecting potential access to the Alberta "Orphan Well Fund".)

Clause 23.03: A delinquent Party that has its status restored prior to the allocation of its Working Interest to the other Parties under Clause 23.02 is to receive the accrued funds applicable to its interest from the Operator within 30 days after restoration of its status.

Clause 23.04: The Operator may also use its rights under Article 5.00 to secure satisfaction of obligations.

Clause 24.01-General: i) This Clause attempts to balance two competing objectives. One is an individual Party's desire to optimize value by having flexibility to explore the market. The other is the Parties' desire to maintain appropriate controls on assignments by another Party.

ii) The Clause includes two Alternates-a consent not to be unreasonably withheld (Alternate A) and a right of first refusal ("ROFR") (Alternate B).

The use of ROFRs has decreased over time. Prior to the 1974 document, a ROFR was the norm, often because large companies had been insistent on inclusion as a control mechanism on potential dispositions by the other parties. The use of the consent mechanism increased after the 1974 document began to be used, although many companies continued to insist on a ROFR as their standard election. The use of ROFRs has decreased since the early 1990s because of industry's experiences with A&D activities and recognition that each Party is probably a seller at some point during the asset life cycle. While some companies still insist on a ROFR as their standard election, most are more selective about when they will require a ROFR (e.g., significant agreements within a core area, potential high-risk, high-reward projects). The changes to this Article in the post-1981 documents were largely designed to narrow the potential application of the Alternate when selected.

iii) Subject to the qualification in the last sentence introduced in the 2015 document, the introduction to the Clause in the post-1990 documents makes it clearer that, for the purposes of Paragraphs 24.01B(h) and (i) and Clause 24.02, the contemplated disposition includes any right to earn a Working Interest for the conduct of operations, even though it is uncertain if and when the assignee will actually earn that Working Interest. This was included for two reasons. One is that the Earning Agreement typically places the farmee/optionee in control of the conduct of earning operations during the earning phase, such that a forward-looking test (rather than a retrospective test of what has been earned to date and the lands that are to be earned for the imminent well(s)) should be used in assessing if the 35% net hectares exception in Paragraph 24.02(e) is applicable to the Earning Agreement. The other is that a linkage of the disposition to the election for each earning well might enable Offerees to make their elections after value added work (e.g., seismic programs, other off block wells) has been conducted by the farmee/optionee, a major impediment to the ability to complete Earning Agreements. (This also impacts the time periods in Paragraphs 24.01B(h) and (i), which might otherwise arguably apply to provide the Offerees with a number of ROFR elections for the same Joint Lands if earning did not occur within the 150-day period provided therein.)

The introduction of the Paragraph 24.02(e) 35% net hectares exception for Earning Agreements in the 2007 document will greatly reduce the number of ROFR notices being issued with respect to Earning Agreements. That being said, there will be some circumstances in which the Disposing Party has entered in a multi-block Earning Agreement respecting Joint Lands and other lands in which it would prefer to defer issuance of a required Disposition Notice for a parcel of Joint Lands that does not fall within the scope of that exception until such time as the farmee elects to conduct the applicable earning operation(s) relating to that parcel. This reflects the fact that the contemplated operations with respect to those Joint Lands were at the farmee's option until such time as it elected to commit to conduct the applicable operation(s).

Canadian Natural Resources Ltd. v. Encana Oil & Gas Partnership, [2008] A.J. No. 1164 (Alta. C.A.), reversing the Chambers' summary proceeding of [2007] A.J. No. 767 (Alta. Q.B.) and sending the case back for a full trial of the issues, is a key case on that issue. It addressed the situation in which the interest being disposed of under the 1990 document was part of a larger transaction in which operations were being conducted in phases. The Disposing Party (Encana) issued the Disposition Notice for this phase of the work program when the commitment to conduct the work program had crystallized after the farmee's selection of its earning blocks. It forwarded its Disposition Notice to CNRL in early December for wells that were to be Spudded in mid-January.

Notwithstanding that the farmee's obligation had not crystallized at the time that the original agreement was completed, one of CNRL's arguments was that the Disposition Notice should have been issued at that time because a "farmout" was regarded as a form of disposition in the 1990 document. Encana, on the other hand, argued that a farmout agreement is not necessarily a disposition-no notice is actually required until a disposition is imminent. The Chambers Judge preferred Encana's argument on this point, and the updates in the 2015 document are consistent with this approach. (See also Paragraph 24.01B(a) and the related annotations.)

As there were no further trial proceedings on the issues in that case, this potentially leaves some ambiguity with respect to the handling of the issue under pre-2007 versions of the document for any Earning Agreement that included a commitment well and one or more optional wells. This type of transaction would typically be referred to as a "farmout" because of the committed well. However, the description of that transaction that actually addresses its essence would be to refer to it as a "farmout and option agreement". It is comprised of a farmout component and one or more indeterminate option components that only truly become farmouts of the applicable Joint Lands if and when the farmee makes the commitment to proceed with the applicable option well. The logic of this categorization of the transaction is apparent when one realizes that the alternative perspective would potentially see an Offeree receiving a series of Disposition Notices under the pre-2007 documents for the same parcel of Joint

Lands because they were not earned within the time period prescribed by Paragraphs 24.01B(h) and (i).

iv) A Party subject to an Article 9.00 or 10.00 cost recovery holds its Working Interest in the applicable Joint Lands. It has full rights under this Clause.

Alternate 24.01A: i) The 20-day deemed consent mechanism was added in the 1990 document to ensure a prompt resolution.

ii) It is reasonable for a Party to withhold its consent if it reasonably believes that the disposition would be likely to affect its interest in a material adverse manner. Usually, this would apply to a reasonable concern about the proposed assignee's financial capability to fulfil obligations under the Agreement. A reasonable concern about the ability to apply Clause 5.05 default remedies against a Disposing Party in default also meets the test.

This reflects the legal test that probably would have been applied under the 1974 and 1981 provisions if a withholding of consent were litigated. A lengthier version of this concept was introduced in the 1990 document to reinforce to the Disposing Party's non-legal personnel the obligation of the Disposing Party to be responsible in the selection of its assignees.

iii) If a Party elects to proceed with a disposition following refusal of consent, a Party that refused its consent would possibly have a remedy for breach of contract. It would have to prove the resultant loss suffered by it, though, to be awarded more than nominal damages.

The decision to withhold consent should be made very carefully. That Party could be liable for damages if the refusal to grant a consent frustrated a transaction and a Court held that the refusal to grant consent was unreasonable. Courts often regard this type of covenant as being mostly for the protection of the Disposing Party-that another Party may not refuse its consent unreasonably. (See, for example, Cudmore v. Petro-Canada Inc., [1986] 4.W.W.R. 38 (B.C.S.C.).) The risk of damages is very real if a Disposing Party lost a disposition in a period of falling commodity prices because a purchaser exercised the typical right to terminate a transaction over the unreasonable refusal of a Party to grant a required consent.

The issue was most recently considered in the context of the CAPL consent provision in IFP Technologies (Canada) v. Encana Midstream and Marketing, 2014 ABQB 470 (Alta. Q.B.). The facts were unusual, in that Encana and IFP had entered into a JOA using a modified 1990 CAPL whereby IFP held a 20% working interest in thermal and enhanced recovery operations with Encana in circumstances in which Encana retained 100% of the interest in primary production. In essence, this saw the ownership linked to the manner in which the rights were produced, such that the interests were, as the Court described them, "competing working interests". Issues arose after Encana disposed of its entire interest in the property to Wiser under an agreement that basically required Wiser to earn its interest for conducting operations with respect to the existing primary production assets, where Wiser's focus was on establishing primary production from the lands. There were no protections included in the IFP agreement offering it any protections if the working interest owner of the primary production rights were to proceed with a development of those rights.

The case raised several issues. One related to the consent not to be unreasonably withheld mechanism in Subclause 2401B(e) of the 1990 document-a parallel provision to Alternate 2401A included in the ROFR process since the 1990 document. IFP had refused its consent because of the adverse impact it believed that a primary production development could have on its future ability to proceed with a thermal development.

In reviewing the consent issue, the Court offered the following summary of the law on the issue: "The burden of proof is on the party asserting consent was unreasonably withheld": Sundance Investment Corp. v. Richfield Properties Ltd. (1983), 41 A.R. 231 (Alta. C.A.). "The party whose consent is required is entitled to base its decision on its own interests alone": Coopers & Lybrand Ltd. v. William Schwartz Construction Co. (1980), 31 A.R. 466 (Alta. Q.B.), aff'd [1981] A.J. No. 537 (Alta. C.A.). "Whether a person has acted reasonably in withholding consent depends on all the factual circumstances": Exxonmobil Canada Energy v. Novagas Canada Ltd., 2002 ABQB 455 (Alta. Q.B.). "The question is not whether a reasonable person might have given consent, but whether a reasonable person could have withheld consent in the circumstances": 1455202 Ontario Inc. v. Welbow Holdings Ltd., [2003] O.J. No. 1785 (Ont. S.C.J.). "In Exxonmobil, Park J reviewed the evidence on an objective basis to determine whether in the circumstances a reasonable person would have refused to consent to the assignment. Proceeding with an assignment in the face of a reasonable refusal to consent is a clear breach of a negative covenant": Exxonmobil.

The Trial Judge noted, "The court should not defer to the party withholding consent, but must assess the reasons for withholding consent and consider whether a reasonable person in similar circumstances would have made the same decision. The court should consider the purpose of the consent clause and the meaning and benefit it was intended to confer."

One of Encana's key arguments was that the withholding of consent was unreasonable if the objecting party would receive as much following the disposition as it would if the disposition had not been made. There were primary production assets located on the lands, and there was no commitment by Encana to advance a thermal development project. The retention of much of the tenure was also at near-term risk if no development activities were conducted, where Wiser's activities allowed tenure to be retained for the benefit of IFP. While IFP may have had an expectation that a thermal project would be advanced, that expectation was not shared. As a result, the Court found that the consent had been unreasonably withheld.

Alternate 24.01B: i) The right of first refusal ("ROFR") mechanisms in the post-1981 documents are more onerous than the provisions in the 1974 and 1981 documents. This reflects the conclusion that industry's experiences with asset rationalization programs since the late 1980s have demonstrated the advantages and disadvantages of including ROFRs in agreements. The ROFR mechanism has been structured on the assumption that only Parties that are serious about attaching the obligation to their interest would include a ROFR. Additional annotations on ROFRs are included in Part III of the Addendum at the end of the annotations.

ii) Courts recognize an implied duty of good faith under ROFR provisions. In GATX Corp. v. Hawker Siddeley Canada Inc., [1996] O.J. No. 1462 (Ont. C.J.), the Court stated: "It is well established that the grantor of a right of first refusal must act reasonably and in good faith in relation to that right, and must not act in a fashion designed to eviscerate the very right which has been given." This implied duty of good faith was also recognized at Trial and the Court of Appeal in Chase Manhattan Bank of Canada v. Sunoma Energy Corp., [2001] A.J. No. 245 (Alta. Q.B.), affirmed [2002] A.J. No. 1550 (Alta., C.A.) (typically referred to as "Best Pacific") and in Hanen v. Cartwright, [2007] A.J. No. 334 (Alta. Q.B.). The Court of Appeal in Best Pacific, though, struggled with a suggestion that this duty would extend to a purchaser that did not have privity of contract with the ROFR holder.

Paragraph 24.01B(a): i) This document introduces a time limitation on the duration of the ROFR. This enables the Parties to retain the benefits of a ROFR process during the initial stages of a project and to have the flexibility of a consent mechanism when the project is mature. On the other hand, Parties that wish to include the more traditional ROFR process can simply use an expiry date more than 50-75 years in the future. The inclusion of this mechanism reflects a policy objective of reducing the number of long duration ROFRs. The structure of the provision avoids the issue raised in the Hanen case, where a party tried to avoid a ROFR on real estate by using an option to purchase with an exercise date after expiry of the ROFR.

ii) The "Insofar as" sentence was added in the 2015 document in the context of the CNRL case reviewed in annotation (iii) on the general annotations on Clause 24.01. It addresses the situation in which multiple wells may be drilled under an Earning Agreement that is not otherwise ROFR exempt under Clause 24.02. It provides the Disposing Party with the ability to defer issuance of a Disposition Notice to the Offerees until such time as it becomes apparent to it that the applicable Joint Lands have been selected in an earning block for a specific committed well. It also eliminates any argument by an Offeree that it has the inherent right to extend a ROFR on one particular block into all of the lands subject to the Earning Agreement.

While a very real potential issue in the pre-2007 documents, this is unlikely to be an issue in practice in the post-2007 documents. The 35% net ha exception in Paragraph 24.02(e) will apply to most larger scale Earning Agreements, and cause them to be ROFR exempt transactions.

Paragraph 24.01B(b): i) A number of commentators have written articles about the potential inclusion of a copy of its P&S Agreement with the notice to minimize the risk that a ROFR notice could subsequently be challenged. As a general statement, they concluded that a Disposing Party that issues only a simple ROFR notice outlining the basic ROFR terms is at significant risk. They note that some Parties attempt to minimize this risk by stating in the notice that the Offerees may review the P&S Agreement at the Disposing Party's offices. They typically note, though, that the most effective way to eliminate this risk is to issue a copy of the form of the P&S Agreement with the ROFR notice.

Since the Disposing Party would not want to negotiate a new sale agreement with an Offeree, this would ensure that the Offerees are aware of all material terms. This greatly increases the likelihood that an agreement resulting from a ROFR election would be finalized quickly. It also motivates a purchaser to finalize the P&S Agreement more promptly.

ii) A ROFR notice should not be issued until the form of the P&S Agreement is complete. The validity of a ROFR notice could be at risk if material changes were subsequently made to the P&S Agreement, as the Offerees would not have made their election on the actual business terms.

Paragraph 24.01B(c): i) The Disposing Party must identify in its Disposition Notice that an allocation has been made, if applicable, so that the Offerees understand if the price is an estimated or allocated value, or represents the actual cash price being received.

ii) The Court of Appeal in Best Pacific considered the ability of an Offeree to use arbitration to challenge an estimated value for a "package deal" under the 1974 document. It determined that the 1974 provision was premised on the consideration not being one that could be matched in kind, such that the arbitration mechanism did not apply to an allocation of a cash value for a property forming part of a larger cash transaction. (This would presumably also apply to the 1981 document.) The Court also stated in *obiter dicta* that the 1990 document appeared to make arbitration available more generally. The application of this Paragraph to the larger transaction scenario has been addressed more clearly in the post-1990 documents. (The difficulties faced by a Receiving Party wishing to challenge an allocated value were reinforced by NAL GP Ltd. v. BP Canada Energy Company, 2010 ABQB 626 (Alta. Q.B.) with respect to what appeared to be a non-CAPL ROFR provision.)

iii) The applicable P&S Agreement may include terms that pertain specifically to other properties. The general view of commentators is that terms that are specific to other assets may be blacked out of the agreement to which the Offerees are provided access.

iv) As the notice and election mechanism under Alternate B is structured in the context of offer and acceptance, a Disposing Party should only issue its ROFR notice if it is confident that its transaction will proceed. This is particularly important when attempting to complete an asset exchange. Otherwise, the Disposing Party could be obligated to dispose of assets to an Offeree when it would prefer to retain the interest.

v) A farmout pertaining only to the Joint Lands can be matched in kind.

Paragraph 24.01B(d): i) This Paragraph is new to this document, and has been included because of the difficult issues inherent with the application of a ROFR to farmouts and optional earning arrangements under the CAPL type ROFR provisions. It should be read in conjunction with the changes to Paragraphs 24.02(c)-(f) of this document and the related definition of Earning Agreement. They recognize the increased tendency for Parties to enter into large scale Earning Agreements, such that it is unlikely for a ROFR to apply to large scale transactions. This Paragraph basically applies the "in kind" mechanism in Paragraph (c) to any farmout type arrangement covering only the Joint Lands, with a modified process for larger deals.

ii) A Disposing Party that enters into an Earning Agreement is obligated to disclose the material terms of the transaction as they relate to the Joint Lands. Various alternatives were explored in conjunction with the inclusion of Paragraphs 24.02(e) and (f). The conclusion was that the most practicable process was to provide the Disposing Party with the option to: (a) provide an allocated cash equivalent value for the earnable Working Interest; or (b) allow the Offerees the opportunity to step into the entire transaction by "matching the deal" (or, as of the 2015 document, the applicable portion of the deal for a multi-block Earning Agreement that is not otherwise ROFR exempt), even though it applies to rights in addition to the Joint Lands. The inclusion of the requirement to disclose some information about the transaction provides a foundation for the Offerees to assess the reasonableness of that value. The Disposing Party should consult with its proposed assignee if it is considering the second option, and it would also need to understand any resultant ROFR issues under other agreements. The proposed assignee will often prefer that the broader option not be given. This does not preclude the Parties from exploring other options at the time.

Paragraph 24.01B(e): i) The Disposing Party has an existing responsibility to the Offerees under its existing contract. As the Disposing Party (not its proposed assignee) is contractually responsible to them for the ROFR value, it should not blindly accept its assignee's proposed ROFR values.

ii) An Offeree that objects to a cash equivalent estimate must object to the estimate within seven Business Days after its receipt.

iii) The corresponding provisions in the 1974 and 1981 documents provided that the reference to arbitration did not suspend the election period. They also provided that the amount determined could never exceed the allocation in the ROFR notice. One of the key findings in Best Pacific on the 1974 document was that Best Pacific had not taken the steps required to exercise or maintain its ROFR within the 20-day period therein. The suspension mechanism was introduced in the 1990 document.

iv) The Party that requests the cash value of consideration to be determined under Article 21.00 assumes the risk that the determined value will be higher than that proposed by the Disposing Party. If the provision stated that the determined value could never exceed that proposed by the Disposing Party, there could be an incentive for an Offeree to refer the matter for resolution if the estimate had been reasonable.

v) Another option would be to have the Disposing Party assign its value and provide that an arbitrator may choose only one of the two alternative values ("baseball arbitration"). The simplicity of that mechanism is attractive, but there are two problems. Firstly, the possibility of an adverse arbitration award might result in Disposing Parties assigning overly conservative cash values to the interest, such that the estimate may be below fair market value. Secondly, such a mechanism might encourage the use of arbitration. If an Offeree's only potential loss is the cost of an unsuccessful arbitration, some Parties may gamble that they could acquire the interest for significantly less than its value.

An arbitrator's discretion to award the costs of the arbitration should deter frivolous references to arbitration in most cases. (See, for example, Section 53 of the *Arbitration Act (*Alberta). If costs were to be shared equally, regardless of the reasonableness of the respective positions, there would be no deterrent to a Party that wished to pursue an unreasonable position.

Paragraph 24.01B(f): i) Commentators have generally concluded that the Disposing Party may not issue a conditional ROFR notice whereby the "offer" may be withdrawn if a package deal or asset exchange is contingent on ROFRs not being exercised. Such a Disposing Party needs to be confident that the transaction would otherwise proceed. It may also wish to manage its risk by requesting waivers without issuing a ROFR notice that the Offerees may accept. This is particularly the case if it is only prepared to dispose of its interest in the asset exchange.

ii) The basic election period was increased from 20 days to 30 days in the 1990 document. A Party receiving a notice is required to conduct a complex evaluation very quickly. As this is often with little or no advance warning, the 20-day period in previous versions of the Operating Procedure would not be practicable in many cases. While this election period will not be attractive to a Disposing Party in a particular instance, it is in the best position to determine the timing of notices. Moreover, presuming that the Parties have elected to use Alternate B because of their genuine desire to include a ROFR, the change ensured that the mechanism was more effective in practice. If the Parties have difficulty with the major principles in Alternate B, it is a strong signal that they should possibly reconsider the selection of this Alternate.

iii) The Offerees have no obligation to respond until 15 days after receipt of the arbitrated value, if applicable. If the obligation were not suspended pending that determination, a Disposing Party may have less incentive to provide a reasonable estimate of the cash value of the consideration. One might attempt to argue that the 15-day election period after the determination of the arbitrated value is too short. However, this ignores the fact that an Offeree which disputes the value would have conducted a detailed evaluation to support its position in the arbitration.

iv) An Offeree's election to purchase the interest creates a contractual obligation that binds both the Offeree and the Disposing Party. An Offeree should not assume that it has latitude to deviate from the terms of the Disposition Notice with respect to such matters as well locations or timing.

This is reinforced by the CNRL case reviewed in annotation (iii) of the general annotations on Clause 24.01, in which the Court of Appeal referred the case back to trial for a determination through regular proceedings after an initial decision through summary proceedings. CNRL had made an unqualified ROFR election and then sought relief from two aspects of the farmee's obligations under the farmout agreement. CNRL wanted to drill the earning wells at a location of its choice in accordance with the farmout agreement (rather than at the farmee's elected locations). It also wanted to drill on a schedule that recognized the operational logistics of conducting the drilling operations (e.g., surface rights, regulatory approvals and supply logistics) that were inherent when receiving the Disposition Notice in early December with a contemplated January 15th commencement date. As the case never did return to trial, it is not clear how those two issues would have been resolved. There was a suggestion by the Chambers Judge in the lower court decision, though, that CNRL should have requested a cash equivalent value under the comparable provision to Paragraph 24.01B(c) because it could not have matched the farmee's consideration in kind.

A Disposing Party in this type of circumstance should also assess the risk to it that an implied duty of good faith could be applied to reflect the Best Pacific decision if it chose to structure its Earning Agreement and the form and timing of its Disposition Notice in a way in which it were substantively eliminating the Offerees' practical ability to exercise the ROFR.

v) A prudent Disposing Party will calculate the ROFR response period carefully under Paragraph 1.02(l) and confirm the final election with any Party it knows is recommending a ROFR exercise before closing the transaction. (See Home Oil, as reviewed in the annotations on Clause 22.02.)

vi) Clause 2.06 would apply to the situation of a successor Operator if the Operator were the Disposing Party.

Paragraph 24.01B(g): The consent mechanism ensures that a Disposing Party is not free to dispose of the interest to a third party that may not have satisfied the criteria at the end of Alternate A. An Offeree should never be forced to pay more than what it believes a property is worth only to avoid an unsuitable assignee that it could have refused if the consent mechanism in Alternate A was chosen. This obligation was introduced in the 1990 document, and was streamlined in the 2007 document. It had not been included in the 1974 and 1981 documents.

Paragraph 24.01B(h): The Disposing Party is to complete its transaction within 150 days after issuance of the Disposition Notice. The 1974 and 1981 documents included a much shorter period for completion of the transaction (within 60 days of expiry of the notice period). Consent to a longer period might be requested as part of a right of first refusal letter if those Operating Procedures apply. The Parties' personnel must be aware of the consequences if they are unable to close their transaction within the unmodified period prescribed by those previous documents. (This is a particular problem if there are also facility agreements associated with the transaction that have 60-day ROFRs.) The modifications to the introduction to Clause 24.01 respecting Earning Agreements ensure that the operative event for Paragraphs (h) and (i) is the completion of the Earning Agreement, not the timing of the applicable earning thereunder. (See also the related annotation on the introduction to Clause 24.01.)

Clause 24.02: The premise of this Clause is that there are certain types of arrangements to which Clause 24.01 should not apply. The potential problems inherent in not having a comparable provision providing clarity for a large-scale corporate transaction are illustrated by Budget Car Rentals Toronto Ltd. v. Petro-Canada Inc. (1989), 60 D.L.R. (4th) 751(Ont. C.A.).

Paragraph 24.02(a): This Paragraph applies to both financial and non-monetary obligations. A Party, for example, may be obligated to deliver production at some future date. The normal Clause 24.01 process would apply to any disposition made after a foreclosure by a lender. That clarification was introduced in the 1990 document. (The Court in Best Pacific also determined that the more general exception in the 1974 and 1981 documents did not apply to any subsequent sale enforcing the security.)

Paragraph 24.02(b): i) The traditional ability to dispose of an interest in return for shares or an interest in a partnership could see those vehicles used artificially to attempt to defeat a ROFR, so has been deleted. This change would not impact assignments to a partnership comprised only of Affiliates, which comprise the vast majority of partnerships to date. If the transaction is not part of a much larger transaction to which the exceptions in Paragraph (c) or (d) apply, the issue is ultimately just the determination of a cash equivalent value.

ii) The 2007 document introduced two limitations on the use of this exception.

One is the inclusion of the *bona fide* reference. It reflects the principle that a Party can't do indirectly what it can't do directly. Industry has traditionally applied this principle to process a transaction as an asset transaction if it is in substance an asset disposition, even though it may be structured as the sale of shares of a specially created Affiliate to which the assets were transferred. (This is also consistent with the way a Court might interpret an attempt to circumvent a ROFR obligation, as occurred in GATX Corp. and as noted with approval in Best Pacific.)

The second provides the Parties with additional protections if a defaulting Party attempts to limit the application of the remedies potentially applicable to its Working Interest under Clause 5.05 by an assignment to an Affiliate. Although this provides clear protection for the Parties, they may already be protected against any such assignment at law or in equity if this were to become an issue. In practice, this would not impact any *bona fide* major corporate transaction, such as a merger or amalgamation.

Paragraph 24.02(c): i) An exemption has applied since the 1974 version if a Party disposes of all or a portion of its interest in substantially all of its P&NG rights in a particular province. A sale of 20% of all of a Party's interests throughout a province would satisfy this exception, for example.

ii) The exception does not apply if the regional disposition is intended to be made under several transactions to different assignees. This qualification was introduced in the 2007 document. However, Best Pacific found that the corresponding provision in the 1974 and 1981 documents applied to a single transaction, and this interpretation would presumably also apply to the 1990 document. The post-1990 Paragraph is also clearer that the single transaction requirement can be satisfied by a multi-party assignee, assuming that the *bona fide* test is met.

iii) The exception includes a *bona fide* Earning Agreement. That clarification was introduced in the 2007 version of the document.

iv) The test for "substantially all" was introduced in the 1990 Operating Procedure. It is linked to net hectares, rather than value, because of the factual basis for the calculation using this methodology. International agreements generally use a value test, rather than a net hectares test. This reflects the different order of magnitude typically associated with the value of an individual block in the respective operating environments. In addition, an explorer that may have 10 blocks in country X could potentially have hundreds or even thousands of different agreements in Alberta.

v) The references "all or substantially all" and "substantially all" have been considered by Canadian Courts (see for example Canadian Broadcasting Corp. Pension Plan v. BF Realty Holding Ltd. (2002), 214 D.L.R. (4th) 121 (Ont.C.A.)) in a variety of contexts involving the interpretation of contracts, taxation legislation and statutes which provide for shareholders' rights upon disposition of material assets by a corporation. In the absence of a contractual or statutory definition like that in this Paragraph, the meaning of "all or substantially all" has been determined to be context dependent and not lending itself to simple arithmetic calculations. Courts have tended to use, in some combination, a quantitative analysis (i.e., a comparison of the proportion or relative value of the transferred property to the total property of the transferor) and a qualitative analysis (i.e., a determination of the nature of a transferor's core business and an inquiry as to whether the transferred property is integral to the transferor's traditional business such that the transfer "strikes at the heart of the transferor's existence and primary corporate purpose"). The 90% "substantially all" test in Paragraph 24.02(c) is designed to eliminate what would otherwise be contextual uncertainties and establish a pure quantitative analysis, so that no scrutiny of the qualitative aspect of the property transfer is required.

Paragraph 24.02(d): i) This Paragraph applies to large transactions being made by a Party and any of its Affiliates, other than Earning Agreements. It applies if the interest being disposed represents a small part of the transaction. It can be easily overlooked when a transaction is being effected. The concept was introduced in the 1981 document, and a clarification was included in the 2007 document for Affiliates. The percentage threshold was increased from 5% to 10% in the 2007 document, to reflect the degree to which A&D transactions typically represent an ongoing component of each Party's asset management strategy. As well, Earning Agreements are handled in Paragraphs (e) and (f) in the post-1990 documents. Based on industry's experiences and expectations, the provision reflects a policy objective that larger transactions should not be unduly impeded.

Assume that A holds a 20% interest in a 1,500 ha block (300 net ha) and it is selling its interests in 12,500 ha in which its average working interest is 25%, including the interest in the Joint Lands. The total net hectares being disposed of would be 3,125 (12 500 X 25%). The net hectares of the Joint Lands would be 9.6% of the total net hectares in the transaction (300/3,125), such that the transaction would fall within the exception.

ii) Segregation (Clause 13.01), by its own terms, creates individual agreements for this calculation, even if the segregation is only stratigraphic.

iii) Lands in which a Party holds only an ORR do not comprise any net hectares, for consistency with industry acreage reporting norms.

iv) Including additional non-prospective acreage that is expiring in a month only to bring the transaction within the 10% threshold seems unlikely to satisfy the *bona fide* test in the Paragraph if the matter were ever litigated. (See the GATX reference in annotation (ii) on Alternate 24.01B.)

v) A Party using this exception should include information on its sale file in sufficient detail that supports the application of the exception in case its use is challenged. There is nothing that precludes another Party from requesting information that demonstrates that the exception applies to a transaction. A Party that erroneously determines that this exception applies has a problem, particularly if this is discovered well after closing.

Paragraph 24.02(e): This exemption was introduced in the 2007 document, and is similar to Paragraph (d). (Also see the annotations on that exemption.) It addresses one type of disposition-*bona fide* Earning Agreements. A ROFR will not apply if the net hectares of Joint Lands that may be earned represent less than 35% of the total net hectares that may be earned under the Earning Agreement (including option rights that ultimately might not be exercised). This structure brings greater clarity to the impact of a farmout that includes optional elements. The use of the higher percentage also facilitates farmouts that comprise Joint Lands and other lands.

Paragraph 24.02(f): This optional Paragraph was introduced in the 2007 document. It allows Parties to exempt all *bona fide* Earning Agreements from the scope of the ROFR obligation. This optional exemption provides Parties with the ability to farm out their Working Interest in a deal that applies only to the Joint Lands or a larger deal without having to comply with a ROFR. This exemption duplicates the Paragraph 24.02(e) exemption for some Earning Agreements, but is a much more transparent exemption to administer.

Subclause 24.04A: i) The CAPL Assignment Procedure applies to all dispositions made under Article 24.00 for which recognition of the assignee under the Agreement is sought. It will not apply to dispositions made by operation of other provisions of this Agreement. Recognition is inherent in the operation of such provisions as the Title Preserving Well penalty and the surrender provisions. Issuance of NOAs for those events would delay recognition and introduce unnecessary administrative effort and possible confusion that typically exceed the benefits of additional documentation.

ii) Pembina Resources Ltd. v. Saskenergy Inc., [1993] 3 W.W.R. 549 (Alta C.A.) pertained to the interpretation of an assignment and novation agreement for a marketing agreement. The assignee attempted to enforce rights formerly belonging to the assignor for contract years prior to the effective date, where the gas had already been delivered by the assignor. The only provision of the A&N agreement referenced in the judgment provided that the third party does "covenant and agree that from and after the Effective Date the Assignee shall be entitled to hold and enforce all of the privileges, rights and benefits of the Assignor under the said Agreement to the same extent as though and to the intent and purpose that the Assignee had become a party thereto in the place and stead of the Assignor."

The purchaser of the gas argued that the clause provided the assignee only with rights for events occurring or accruing after the effective date. The Court did not agree with that argument. It found that the reference to the effective date modified "entitled to hold", rather than "privileges, rights and benefits of the Assignor". In essence, the Court determined that the assignor no longer had any status to commence an action for benefits accruing to the period prior to the "effective date", such that the assignee was placed in the shoes of the assignor as of the effective date.

When considering this case, it is important to recall that the references to the assumption or retention of rights, benefits, obligations and liabilities in Clauses 3.01(c), (e) and (f) of the 1993 CAPL Assignment Procedure were structured to modify rights and obligations, rather than the entitlement to those rights or the responsibility for those obligations. It was unclear from the case how (or if) the A&N in question addressed the allocation of other rights and obligations between the assignee and assignor for pre and post effective date scenarios. This had caused some concern that assignees might be held responsible for pre-effective date obligations because of the case. This appears unfounded, though. A review of the materials filed with the Court of Appeal confirmed that the A&N in the case included in a paragraph not referenced in the judgment a clear statement that nothing would "be construed as a release of the Assignor from any obligation or liability which may have accrued prior to the Effective Date."

The other distinguishing factor in an Operating Procedure scenario is a well-established industry practice to the contrary of that outcome, particularly in the context of such matters as J.V. audits. It would be an odd result if an assignee that had not been involved in a property prior to the "transfer date" would be exposed to the possibility of either a positive or negative adjustment resulting from an audit pertaining to the period prior to the "transfer date". As the assignee would not have any income from the acquired interest prior to the effective date, the allocation of either benefits or obligations to it for that period would violate the "matching principle" that forms the foundation of the accrual basis of accounting.

Subclause 24.04B: i) As noted in the annotations on Clause 13.01, Article 13.00 of the 2007 version of the document was modified, so that each portion of the Joint Lands with different Working Interests is managed, in effect, under its own separate agreement. The outcomes in this Subclause are consistent with those contemplated in the CAPLA Segregation Procedure.

One of the historical issues relating to segregation under previous versions of the document has been the inclusion of additional third parties in the applicable notice of assignment (NOA) if those additional third parties are involved in other portions of the lands subject to the Agreement because only the Operating Procedure was subject to segregation. This Clause supplements Clause 13.01 by stating that the third parties for any such NOA may be limited to only those third parties that hold either a Working Interest or another form of interest (e.g., farmor holding ORR) in those Joint Lands subject to the NOA.

ii) To avoid a proliferation of assignment documentation, the assigning Party may use a single NOA to effect an assignment of interest under more than one of the separate agreements deemed to be created under Clause 13.01 if: (a) it is disposing of an interest under all of the separate agreements in which it holds an interest; or (b) it chooses to list all the segregated blocks to which the NOA pertains and the specific interests being assigned for each such segregated block. The latter NOA would see listed in the NOA all third parties having interests in any of the applicable segregated blocks, even if the third parties or their interests differed between the segregated blocks. This Subclause allows the assigning Party to list as a third party to the NOA a third party that holds an interest in any segregated block to which the NOA pertains. It is designed to ensure that a Party will not have grounds to reject a NOA because the third parties do not have consistent interests in all of the blocks to which the NOA pertains.

iii) A Party assigning an interest in circumstances in which Clause 13.01 will apply must be aware of any special issues that could arise as a result of the creation of a segregated block. Issues relating to such matters as an outstanding area of mutual interest, joint Production Facilities and, if stratigraphic segregation, the handling of existing wellbores, would need to be addressed on a transaction specific basis.

Clause 25.01: A similar clause was considered in Apex Mountain Resort Ltd. v. British Columbia, [2000] B.C.J. No. 1099 (B.C.S.C.), affirmed, [2001] B.C.J. No. 1596 (B.C.C.A). The Court found that the provision in that case did not go so far as to impose an obligation that would be inconsistent with that agreement. That provision did not include the "reasonably required" qualification historically included in the CAPL provision.

Clause 25.05: This Clause is included to minimize the possibility that a Party could successfully turn to a Court for relief if a provision were being used to its detriment. A Court has limited jurisdiction to provide a Party with relief against forfeiture, notwithstanding the clear wording of an agreement. (See, for example, Section 10 of the *Judicature Act* (Alberta).)

Clause 25.06: One of the requirements for approval of a holding in Alberta is that there is "common ownership" in the area to which the holding applies, and the AER reserves the discretion to terminate a holding if this requirement is no longer satisfied. This Clause is designed to restrict a Party from attempting to terminate or alter the holding based on a change in ownership in a portion of the area to which the holding applies. It is based on the premise that the AER is unlikely to be concerned as long as the "well density" and "buffer" and "interwell" distance requirements under the holding are still being satisfied.

Clause 25.07: This Clause is included because of the increased emphasis on avoidance of conflicts of interest under corporate compliance policies. Internal policies and regulatory requirements also restrict the use of confidential information in the trading of securities. Clause 3.07 of the 2007 document also introduced a requirement to maintain suitable internal controls. These modifications were included in the 2007 document in the aftermath of the Enron investigation, in recognition of the degree of reliance on the Operator's financial reporting and greater regulatory requirements for corporate compliance with financial reporting standards, such as the U.S. Sarbanes Oxley Act.

ANNOTATIONS-ADDENDUM

I - Special Circumstances In Which Amendments Might Be Considered

These annotations are designed to provide an overview of some of the circumstances in which amendments to the Operating Procedure may be appropriate. The nature of some of the potential amendments is that they might most effectively be addressed through the inclusion of additional provisions in the Head Agreement that will supplement, override or replace the applicable provisions of the Operating Procedure. Others would more effectively be addressed through an amendment to the specific provisions of the Operating Procedure, such as the inclusion of a proviso or the modification of a time period. An electronic document preparation tool would ideally allow users to make changes in a way that is clear to users.

This information has been included to assist users in understanding the document, and is not intended to be a complete examination of either those situations or the types of potential amendments that should be considered.

The one caution in this area is that the benefits of customization have to be weighed against the associated cost. While specific amendments may be appropriate and acceptable to the Parties, the benefits of standardization begin to be lost with customization that reflects only organizational preferences. Every incremental modification above what is required for a particular project introduces a point of potential misalignment that could, by itself, delay or frustrate the completion of the Agreement. It is also important to remember that an adjustment to one provision will often have consequences in other areas of the document that will often not be appreciated by users.

A. Remote Areas/Seasonal Access

- Potential timing issues for Commencement of Operations under Clauses 7.01 and 10.03, particularly if significant consultation is anticipated to be required to obtain access and regulatory approvals.
  - Increase to the period of Commencement in the post-1990 documents and potential application of Force Majeure Article mitigate risk on this issue significantly, though.
  - The simplest modification is to increase by 60-120 days the time periods prescribed by those Clauses, and Parties should identify this possibility in their precedent election sheet to minimize the possibility it might be overlooked.
  - Possible revision of definition of "Commencement" in areas with difficult access to link to initiation of surface construction, rather than Spudding.
    - Possible further requirement that Spudding has to occur within X days of completion of surface construction?
- Should consider if there are any special facilities issues that need to be addressed in the Head Agreement about construction of new regional facilities or access to existing facilities owned by a Party.

B. Sour Gas

- Potential timing issues for Commencement of Operations under Clauses 7.01 and 10.03 if significant consultation is anticipated to be required to obtain surface access and regulatory approvals.
  - Increase to the period of Commencement in the post-1990 documents and potential application of Force Majeure mitigate risk on this issue significantly, though.
  - The simplest modification is to increase by 60-120 days the time periods prescribed by those Clauses, and Parties should identify this possibility in their precedent election sheet to minimize the possibility it might be overlooked.
  - The nature of the contemplated pre-Spud activities may warrant setting up an interim AFE, as contemplated in annotation (viii) on the definition of AFE in Clause 1.01.
- Possible modification to Subclause 3.01C for the overexpenditure scenario for high-cost operating areas.
  - Mechanism in which a Party could elect to become a Non-Participating Party on the same basis as for a Deepening under Article 10.00 once costs exceed a specified overexpenditure threshold (e.g., 35%, 50%, etc.)?
    - Restriction that a Party could not exercise this right during an emergency or during drilling difficulties.
    - Would also need to be clear about expectations for Abandonment costs.
- May want to modify Operator's liability to require Gross Negligence or Wilful Misconduct to be by Operator's Senior Supervisory Personnel. (See annotation (v) on the definition of Gross Negligence or Wilful Misconduct.)
- Might want to be more specific about consultation expectations and status reports in Clauses 3.05 and 3.09.
- Need to review Clause 3.11 insurance coverage carefully.
  - Individual duty to have control of well insurance coverage at a prescribed level?
    - Exception for all (or some) of the initial Parties and their Affiliates, to recognize that financial viability of at least some of the current owners is not an issue?
    - May be beneficial to include a mechanism to review the selection of Alternate 3.11C(b) if there is a change of Parties.
- Need to review the Clause 10.04 election carefully for the ability of a Non-Operator to operate an Independent Operation in which the Operator participates.
- Should consider if there are any special facilities issues that need to be addressed in the Head Agreement about construction of new regional facilities or access to existing facilities owned by a Party.

C. High-Risk, High-Reward Wildcat Exploration Programs

- Potentially some of the same issues identified in A and B above, depending on the location and type of production anticipated.
- Some special features to consider if: (i) the lands are held by more than two Parties and no single Party holds a dominant Working Interest; (ii) there is a large amount of open P&NG rights in the area; (iii) none of the Parties is otherwise active in the project area; and (iv) the initial Operations can confirm or invalidate the play type.
  - Ability to approve Operations of a certain type or below a certain cost threshold through a less than unanimous vote?
  - An Operating Committee mechanism of some sort as a vehicle for joint planning and expenditure forecasting if significant capital expenditures forecast?
- Possible inclusion of a mechanism whereby G&G programs within the AMI/project area for at least some period must be proposed to the other Parties as a Joint Operation.
  - Modification whereby a Non-Participating Party may not participate in a well within the area of a G&G program conducted by fewer than all of the Parties without equalization into the program on some basis?
    - Variation so that equalization isn't required if at the time the well is proposed it already has proprietary or trade seismic at the well location?
      - Protects a Party with 2D seismic data from a 3D program it believes is unnecessary.
- Inclusion of a modification to Clause 10.07 cost recovery for certain types of Exploratory Wells so that there is a "forced farmout".
  - Could apply, for example, to the first X Exploratory Wells drilled under the Agreement, the first well on a particular "Prospect", Exploratory Wells Spudded prior to a specified date or Exploratory Wells not less than X km from another well that penetrated the Z formation.
- Should consider if there are any special facilities issues that need to be addressed in the Head Agreement about construction of new regional facilities or access to existing facilities owned by a Party.

D. Pattern Drilling Programs (Shallow Gas/Conventional Heavy Oil)

- Operating Procedure historically has not optimally handled multi-well pattern shallow gas or conventional heavy oil drilling programs in which well results from individual wells are not expected to vary materially.
- Potential modifications could facilitate approval and conduct of the drilling program.
  - Use of optional Subclause 10.02G or subsequent amendment whereby it will be selected if not originally selected.

        - Negotiation of technical parameters under which the Operator may automatically proceed to test wells without requirement for authorizations for each well?

E. Complex Horizontal Well Operations

- It is critical to assess carefully the degree to which the document, in its unamended form, offers enough content for complex Horizontal Well Operations that are contemplated, such as secondary or tertiary recovery schemes.
    - Does it suitably address recognized producing issues and the range of issues relating to the use of unique technology?
    - Does it provide the appropriate balance of flexibility for the Operator and financial controls for the Non-Operators?
        - Can the Operator make the necessary real time decisions inherent in the contemplated horizontal Operations?
        - Are there appropriate protections included for the benefit of the Non-Operators, so that they are comfortable with the implications of agreeing to participate in (or electing not to participate in) any particular horizontal Operation?
        - A number of additional issues should be considered by the Parties, such as:
            - Are any revisions desired to the definition of "Development Well" or the definition of "Spacing Unit"?
            - Are the Parties comfortable with the flexibility afforded the Operator under Subclauses 3.01E and 10.02H?
            - Are the Parties comfortable with a separate Completion election, as contemplated in Clause 8.02?
- Modifications introduced in the 2015 document add far greater functionality in the document and also accommodate additional customization by the Parties in their Head Agreement respecting development of a Well Pad.

F. Major Shale And CBM Operations

- Is the project of a potential scale that the CAPL Operating Procedure might not be an appropriate foundation?
    - The 2015 CAPL Operating Procedure offers a much better starting point than the 2007 document.
        - The “waiting functionality” provisions of the document contemplate modules of customization to address Multiple Well Drilling Programs, Multiple Well Completion Programs and the development of Well Pads and a potential evolution to more of a project-based approach as development approaches.
        - Additional content was added to accommodate long reach Horizontal Wells.
    - The size of the land base, the expenditure profile, the size of the resource base and the influence of international partners are likely to see some partner groups gravitate to a project based AIPN Unconventional Resource Operating Agreement (“UROA”) as a platform, with significant customization to reflect the Canadian regulatory/tenure and legal environment.
- Clear identification of rights (e.g., shale or coal horizons only?).
    - Reserved formations mechanisms.
- Need to understand the expectations for involvement of the Non-Operators in the planning of Operations, given the likelihood that there will be more than two owners in many cases.
    - Establish an Operating Committee model, if warranted by the capital program, owner % and ongoing similarities to units?
        - Approval thresholds?
- Will there be a formal budgeting process of some sort?
    - Minimum committed program for initial period?
- Any special environmental and consultation requirements?
    - Special access issues probably associated with this type of project, notwithstanding the use of drilling pads.
        - Drilling density and water handling, with impact magnified by success.
    - Extensive stakeholder consultation probably required in many cases.
- Expectations for advocacy efforts with regulators/lessors?
    - Additional financial and tenure issues associated with this type of project.
        - Offsets and continuation mechanisms.
        - Potential royalty issues-deductions against royalty, flaring.
- Different handling of pilots and development projects?
- Any modifications to such definitions as “Commercial Quantities”, “Equipping”, “Paying Quantities”, etc. required?
- Basis for proceeding independently?
    - What is the appropriate consequence of non-participation?
    - Modifications to Casing Point mechanism?
        - Differences between Exploratory Wells, “stepout wells” and Development Wells?
    - Link development to previous similar activities, rather than conventional wells.
    - Project based or well specific?
    - Project based Abandonment?

G. “North of 60” Operations

- Important for users to understand those principles of the Operating Procedure that translate well to northern operations, those that need to be modified somewhat and those that need to be rethought entirely.
    - Many of the modifications to the post-1990 versions of the Operating Procedure were made to provide a more effective platform for more complex projects, such as northern operations and large-scale shale projects.
    - Degree of required modification will generally increase as one moves further north because of the increasing logistical challenges and the potential magnitude of the costs.
- Need to understand the expectations for the involvement of the Non-Operators in the planning and possibly conduct of Operations, given the likelihood that there will be more than two owners in many cases.
    - Establish an Operating Committee model from the commencement of the project?
    - Use of a more traditional AFE Operator/Non-Operator approval model under which an Operating Committee may be established at a later date (i.e., development stage or agreement of the owners)?
        - Agreement would need to be clear on expectations for such matters as the technical dialogue process, the budget process and approval of certain items through less than unanimous approval.
    - Need to be clear about expectations for charging internal labour costs associated with any joint technical teams.
- Need to be clear about local benefits obligations and expectations.
    - May wish to add some provisions in the Head Agreement about the negotiation of local benefits agreements and the requirement for compliance.
    - May wish to expand Subclause 3.03B on the basis outlined in the annotations to provide additional clarity about the expectations for contracts being entered into for the Joint Account.
    - May wish to expand the consultation component of Clause 3.09 about the degree to which Non-Operators may participate in the consultation process and the expectations for status reports from the Operator.
        - Need to confirm that the document ensures that consultation costs associated with activities conducted for the Joint Account are chargeable for the Joint Account.
    - May wish to include staffing and supply of goods and services as part of the budget process.
- Need to be clear about interface with regulators and the responsibilities of the “designated representative”.
    - To what degree are the Non-Operators to be consulted with respect to non-routine issues?
        - Handling of applications for significant discovery licences, etc.
    - Need to be clear about prioritization if multiple “regulators” involved in activities (i.e., areas with settled land claims).
- Exploration and appraisal operations.
    - Possible inclusion of a mechanism whereby G&G programs within the AMI/project area for at least some period must be proposed to the other Parties as a Joint Operation.

        - Modification whereby a Non-Participating Party may not participate in a well within the area of a G&G program conducted by fewer than all of the Parties without equalization into the program on some basis?
        - Variation so that equalization isn't required if at the time the well is proposed it already has proprietary or trade seismic at the well location?
            - Protects a Party with 2D seismic data from a 3D program it believes is unnecessary.
    - May wish to modify definitions of Exploratory and Development Wells from a distance test to a technical test and to add a definition of Prospect.
        - Add definition of "Appraisal Well", with consequential penalty impact?
    - May wish to have some types of Operations approved through a less than unanimous approval process, so that Parties are using similar information bases.
    - How to manage cost allocation issues associated with the north, particularly for the far north?
        - Allocation of mobilization costs to the north across a drilling program.
        - Allocation of standby charges inherent in maintaining equipment in areas of the north on a year-round basis.
        - Allocation of charges for use of a staging and base camp area owned by fewer than all of the Parties.
    - How to manage overexpenditures?
    - Suitability of cost recovery penalties or land forfeiture penalties?
    - Suitability of "cash premium" penalties, such as commonly used internationally?
        - If so, what are the percentages, the reinstatement mechanism and the related timing window?
- May wish to address expectations for "Pre-Development" and "Development" in the Head Agreement in the context of the different regulatory and operating environment.
    - Does the level of participation by the Non-Operators in the planning of Operations increase?
    - What is the approval threshold for studies and the preparation of the Development Plan?
    - Expectations for approval-a project or well-by-well approvals?
    - Will a Party be able to drill additional Development Wells independently once the field is on production or will additional drilling be conducted under unit type approval processes?
        - Additional Development Wells drilled through a less than unanimous approval process?
        - No ability to drill a Development Well independently if the applicable approval threshold is not obtained?
    - Basis for approval of subsequent Production Facilities or expansions?
        - Potentially advantageous to use less than unanimous approval process.
        - Is there a process in which facilities shift to being managed under a CO&O agreement?
- A potential range of marketing type issues associated with transportation commitments.
    - A front-end mechanism to encourage coordination of transportation commitments, particularly for the far north?
    - What are the consequences if a Party fails to obtain sufficient transportation capacity to handle its share of production?
        - To what degree would the traditional WCSB marketing fee mechanism provide suitable compensation?
- Inclusion of a mechanism under which an abandonment fund may be established?
    - Special tax issues respecting an abandonment fund.

II - Case Law Respecting Fiduciary Obligations And Breach Of Confidence

A. Fiduciary Obligations

There have been several major cases dealing with fiduciary obligations since the late 1980s, and some have been in the context of the oil and gas and mining industries. As noted in the annotations in Section C below, fiduciary obligations may also be raised in conjunction with a claim for breach of confidence when a misuse of confidential information is alleged.

One example is Lac Minerals v. International Corona Resources Ltd., [1989] 2 S.C.R. 574 (S.C.C.), affirming in part (1987), 44 D.L.R. (4th) 592 (Ont. C.A.) and (1986), 25 D.L.R. (4th) 504 (Ont. H.C.). As noted in more detail in the annotations in Section C below, the case related to the use of information disclosed in confidence during negotiations to acquire promising adjacent mineral claims.

The Supreme Court of Canada confirmed the finding of the lower Courts that Lac was liable to Corona. Based on the breach of confidence in this instance, it applied the doctrine of constructive trust to award the other mineral claims to Corona, so that Lac could not profit from its misuse of the disclosed information. (Also see, Midcon Oil & Gas Ltd. v. New British Dominion Oil Co., [1958] S.C.R. 314 (S.C.C.) respecting the doctrine of constructive trust.) The Supreme Court found Lac liable for breach of confidence (Section C below), but the majority found that there was no breach of a fiduciary duty, stating in part, "…the fact that confidential information is obtained and misused cannot itself create a fiduciary obligation. No doubt one of the possible incidents of a fiduciary obligation is the exchange of confidential information and restrictions on its use. Where, however, the essence of the complaint is misuse of confidential information, the appropriate cause of action in favour of the party aggrieved is breach of confidence and not breach of fiduciary duty."

The Supreme Court recognized that a fiduciary relationship does not normally arise between arm's length commercial parties. In concluding that there was no fiduciary relationship in this particular case the majority applied the test from a dissenting judgment in an earlier case (Frame v. Smith, [1987] 2 S.C.R.99 (S.C.C.)) to determine whether a fiduciary obligation exists. The three general characteristics in this test were: "(a) the fiduciary has scope for the exercise of some discretion or power; (b) the fiduciary can unilaterally exercise that power or discretion so as to affect the beneficiary's legal or practical interests; and (c) the beneficiary is peculiarly vulnerable to or at the mercy of the fiduciary holding the discretion or power". The majority of the Court in Lac concluded that Corona was not vulnerable because it could have protected itself by negotiating an appropriate confidentiality agreement. The minority, which chose to emphasise an expectation of loyalty rather than vulnerability, would have found a fiduciary relationship.

Since the Lac decision the Supreme Court of Canada has tended to emphasize the reasonable expectation of loyalty as well as vulnerability as the hallmark of the existence of a fiduciary duty or relationship in cases such as Hodgkinson v. Simms, [1994] 3 S.C.R. 377 (S.C.C.) and Alberta v. Elder Advocates of Alberta Society, [2011] 2 SCR 261 (S.C.C.). The leading case is now Elder Advocates. In that decision, the Court stated that in addition to the vulnerability arising from the relationship as described in Frame v. Smith, a claimant must also show: (1) an undertaking by the alleged fiduciary to act in the best interests of the alleged beneficiary or beneficiaries; (2) a defined person or class of persons vulnerable to a fiduciary's control (the beneficiary or beneficiaries); and (3) a legal or substantial practical interest of the beneficiary or beneficiaries that stands to be adversely affected by the alleged fiduciary's exercise of discretion or control.

Alberta cases dealing with the law of fiduciary obligations in an oil and gas context include: (a) Consolidated Oil & Gas Inc. v. Suncor Inc., [1993] A.J. 485 (Alta. Q.B.), which considered fiduciary obligations and the "duty of good faith"; (b) Erehwon Exploration Ltd. v. Northstar Energy Corp., [1993] A.J. No.916 (Alta. Q.B.), which considered, among other issues, fiduciary obligations and the "duty of good faith" in circumstances in which a CAPL Operating Procedure applied, and determined that an Operator is in a fiduciary role with respect to many of its functions, where the determination is issue and fact specific and must be examined in the context of the particular contract; (c) Prairie Pacific Energy Corp. v. Scurry-Rainbow Oil Ltd., [1994] A.J. No. 36 (Alta. Q.B.), which considered the nature of an Operator's fiduciary obligations in the context of a pre-CAPL Operating Procedure; and (d) Novalta Resources Ltd. v. Ortynsky Exploration Ltd., [1994] A.J. No. 1101 (Alta. Q.B.), which considered, among other issues, the nature of the Operator's fiduciary obligations in the context of the 1981 CAPL Operating Procedure and the "duty of good faith".

The leading Alberta case on the issue of fiduciary obligations in the context of the CAPL Operating Procedure is Luscar Ltd. v. Pembina Resources Ltd., [1994] A.J. 864 (Alta. C.A.), reversing [1991] A.J. No. 1051 (Alta. Q.B.), leave to appeal to the Supreme Court of Canada denied, [1995] S.C.C.A. No. 6. The case pertained to a pre-CAPL form of agreement that the defendant may have breached many years previously with respect to several AMI acquisitions. The Trial Judge determined that the plaintiffs were entitled to a remedy in equity because of the Operator's breach of fiduciary obligations with respect to the AMI acquisitions and other duties (including for the latter a duty to share the Operator's proprietary interpretations so that the parties could jointly pursue new opportunities and a duty to optimize exploration and exploitation of the joint rights).

In reversing the decision, the Court of Appeal stated in part: "It may well have duties of loyalty arising from its position, and not be able to use advantages it gains exclusively as operator. For instance, if it deliberately misrepresented well results or facts, that might be a breach of a fiduciary duty such that equity would require disgorgement of any profit gained. While I accept that there may be fiduciary aspects of the duties of an operator, not every duty is fiduciary. The mere fact a contract imposes responsibilities on one party upon which another relies, does not mean the first party is automatically a fiduciary with respect to the duty created. Moreover, where a specific term of a contract addresses an issue, the contractual remedy may properly redress the wrong, thereby reducing any vulnerability. The parties, having addressed the issue specifically by contract, without making the duty to give notice a fiduciary one is also a factor to be considered...Thus a party may have fiduciary obligations arising from its relationship, but not every obligation is a fiduciary one." The Court of Appeal also had difficulty with finding the dependency required for a fiduciary relationship when parties were on an equal footing.

One instance in which a fiduciary obligation might be found is in the circumstance in which the Operator has an interest in offsetting lands in the same pool if it stands to profit by not placing a well on production respecting the Joint Lands. (See Moco Resources Ltd. v. Unocal Canada Resources, [1997] A.J. No 116 (Alta. Q.B.).)

B. Good Faith Performance of Contracts

Another important development in the law of contractual relationships is the recognition by the Supreme Court of Canada in Bhasin v. Hrynew, 2014 SCC 71 (S.C.C.) that good faith contractual performance is a general organizing principle of the law of contracts and that one manifestation of that principle is a common law duty to act honestly in the performance of contractual obligations. This duty does not imply a duty of loyalty (that is the standard to which a fiduciary is held) or disclosure, but it does require that a party have "appropriate regard" for the interests of the other party and "not seek to undermine those interests in bad faith". "[P]arties must not lie or otherwise knowingly mislead each other about matters directly linked to the performance of the contract." The duty is a general duty of contract law, and, as such, applies to all contracts. It is not excluded by an entire agreement clause, and, like the doctrine of unconscionability, parties are not free to exclude it. However, parties may expressly relax the requirements of the doctrine, so long as they respect its minimum core requirements.

The duty of "good faith" has been considered in an oil and gas context many years prior to Bhasin in Mesa Operating Ltd. v. Amoco Canada Resources Ltd., [1994] A.J. No. 201 (Alta. C.A.), affirming [1992] A.J. No. 287 (Alta. Q.B.). In essence, the case pertained to a situation in which a half-section subject to Mesa's ORR and held by Amoco was included in an acreage-based pooling with another half section in which Amoco also held a working interest with other owners. The critical finding of fact was the determination that the vast majority of the reserves were within the half-section subject to the ORR. The Court at trial found for the ORR holder on the basis of the "duty of good faith." The Court of Appeal agreed that Amoco was liable to Mesa, but was not prepared to do so on the basis of a "duty of good faith". The Court of Appeal judgment stated in part; "The rule that governs here can, therefore, be expressed much more narrowly than to speak of good faith, although I suspect it is in reality the sort of thing some judges have in mind when they speak of good faith. As the trial judge said, a party cannot exercise a power granted in a contract in a way that "substantially nullifies the contractual objectives or causes significant harm to the other contrary to the original purposes or expectations of the parties."

C. Breach of Confidence

The law respecting breach of confidence is also an evolving area. The leading case of Lac Minerals v. International Corona Resources Ltd., [1989] 2 S.C.R. 574 (S.C.C.), affirming (1987), 44D.L.R. (4th) 592 (Ont. C.A.) and (1986), 25 D.L.R. (4th) 504 (Ont. H.C.), for example, related to the use of information disclosed in confidence. In essence, the case pertained to a situation in which Corona disclosed sensitive proprietary information about an adjacent mineral property to Lac in the early stages of a possible joint venture. They did not enter into a confidentiality agreement. Lac proceeded to acquire an adjacent property that the information indicated to be prospective, where the disclosed information was found to be the "springboard" to the acquisition.

The Supreme Court determined that the test for breach of confidence required an injured party to establish three elements: (a) that the information conveyed was confidential; (b) that it was communicated in confidence; and (c) that it was misused by the party to whom it was communicated. The absence of a confidentiality agreement was not fatal to Corona's claim in that case, as the Supreme Court placed significant weight on industry practice in the mining industry. Although the conventional remedies for breach of confidence would be an accounting for profits or damages, the Supreme Court chose to apply the remedy of constructive trust, and awarded Corona the adjacent property in its entirety. The Supreme Court did not go so far as to include as part of the third element that the disclosure was to the detriment of the disclosing party, although this would typically be inherent in any claim for breach of confidence that escalated to litigation.

The remedy that will be applied for a misuse of confidential information is dependent on the particular circumstances. In Ontex Resources Ltd. v. Metalore Resources Ltd. (1993), 13 O.R. (3rd) 229 (Ont. C.A.), application for leave to appeal dismissed, [1993] S.C.C. A. No. 370, the operator of a mining property intentionally withheld information it was required to share with the other party on an annual basis. The operator proceeded to purchase the property from the other party and to acquire adjacent properties that were prospective for its own account. Although the Court of Appeal rescinded the sale agreement, it was not prepared to find on the facts that there was a constructive trust for the adjacent lands.

One outstanding issue raised by the Ontex case is the degree to which an Operator must make full disclosure of all information it possesses for a property when trying to purchase another Party's interest. It seems clear from the decision that non-disclosure of information that the Operator is required to provide would potentially leave the purchase open to challenge, unless the selling Party was consciously prepared to make the disposition without access to that information. Clauses 1.05 and 18.04, on the other hand, should enable purchasers to make an offer based on information to which the vendor has no entitlement under the Agreement.

The breach of confidence issue was considered in an oil and gas context in Cinabar Enterprises Ltd. v. Richland Petroleum Corp., [1998] A.J. No. 891 (Alta. Q.B.). This case pertained to a situation in which a party shared information in the early stage of potential negotiations without a confidentiality agreement in place. The party receiving the information realized from the discussion that the lease had terminated years previously and proceeded to acquire a new lease. This information was also in the public domain, such that the other party could have easily confirmed this using data that was readily available to it.

Although the Court quoted the Lac test with approval, the Court found that the information was not confidential or conveyed in confidence. These findings were based on the fact that the information was already in the public domain and the determination that the disclosing party did not have the belief that the information could be used to its detriment (e.g., its belief that its lease was valid). (It is also important to note that the facts also indicated that the other party had independently developed a different play on the lands prior to the meeting.)

The Court considered the custom and practice respecting the sharing of information in the oil and gas industry, but did not have to make a determination on this issue after the finding that the shared information was not confidential.

Given the evolving nature of the law in this area, users should ensure that they comply with the obligations in the Agreement for the handling of information. Parties disclosing confidential information in commercial negotiations should also attempt to control their own destiny by entering into an appropriate confidentiality agreement prior to any such disclosure.

III - Miscellaneous Annotations On ROFRs

i) There may be instances in which the Parties choose to include a "first right of negotiation" in their Agreement instead of either of the presented options. In essence, this type of mechanism requires a Party contemplating a disposition to solicit offers from the other Parties within a prescribed period (typically 30 days). If the Party does not accept an offer from the other Parties, it may try to obtain a better offer from the marketplace for a prescribed period (e.g., 180 days) without any ROFR type obligation attaching to a transaction more favourable to it. (See Optional Alternative No. 2 of Article 12.2(F) of the AIPN Operating Procedure for a sample provision of this type.) This type of provision was not included because of the view that the Alternate would not be frequently used and that a Party considering a disposition in Western Canada would typically be motivated to determine the interest of the other Parties in the property in practice.

ii) A Party that does not comply with a right of first refusal obligation faces the risk that a Court could order specific performance if the acquiring party knew or should have known that there was a ROFR. See, for example, Canadian Long Island Petroleums Ltd. et al. v. Irving Industries (Irving Wire Products Division) Ltd. et al, [1974] 6 W.W.R. 385 (S.C.C.), affirming, [1973] 5 W.W.R. 99 (Alta. S.C., App. Div.), in which it was clear that the assignee was aware of the ROFR. Since that decision, Alberta has amended *The Law of Property Act* to address a right of first refusal. Section 63 provides that a right of first refusal is an equitable interest in land and may be registered under that Act (application limited to freehold). The common law cases on priority now apply to registrable rights of first refusal in Alberta. The failure to file a caveat protecting a right of first refusal had a negative impact on the offerees in Calcrude Oils Ltd. v. Langevin Resources, [2003] A.J. No. 1575 (Alta. Q.B.).

iii) The proposed assignee may also hold a ROFR if it already owns an interest in the property. If so, the assignee should exercise its ROFR. The owners exercising the ROFR have priority over the assignee under the Operating Procedure. If another offeree exercised its ROFR and the assignee did not exercise, the exercising offeree would acquire the applicable interest in its entirety.

iv) Unit agreements seldom include any restriction on dispositions. Operations for the unitized zone are conducted under the unit agreement. Some assume, therefore, that the Operating Procedure no longer applies to the unitized zone, such that a ROFR obligation therein does not apply to the unitized interest. Unless the unit agreement specifically states that it has superseded the prior agreement for all purposes, the generally accepted view is that a ROFR in the land agreement continues to apply to the owners in the tract.

v) Similar considerations as for a unit agreement potentially apply to the interrelationship between a subsequent non-cross-conveyed pooling agreement and the original agreements under which the pooled interests were held. If, for example, the pooling agreement included a consent mechanism and the original agreement included a ROFR, the ROFR in the original agreement arguably still applies unless there was a clear intention in the subsequent agreement to override the ROFR. This type of pooling agreement is typically structured as a vehicle to allow the lands to be combined for development and production purposes only during the period in which the well is productive, with reversionary processes back to the original agreement. To minimize potential confusion later, Parties entering into such a pooling agreement should be clear at the time about their expectations for the original ROFR.

vi) A Disposing Party must check both the land and J.V. agreements for ROFRs. There is a tendency for vendors and purchasers to focus only on the land agreements. However, the failure to discover a ROFR in a J.V. agreement when researching title is at least as serious as the failure to note a ROFR under a land agreement. It is also important to remember to check a freehold lease that has been granted by an industry player, such as Encana (PanCanadian), for a possible ROFR.

vii) The ROFR process in Article IX of the 1999 PJVA CO&O Agreement is similar in many ways to the 1990 CAPL provision, but does have major differences. In addition to differences because of the subject matter, the PJVA provision includes two optional Paragraphs in the ROFR exemptions in Clause 902. One pertains to a disposition of substantially all of an Owner's working interest in the wells producing to the facility. The other is for a disposition of an interest in the facility that corresponds to the wells being produced to the facility.

viii) The ROFR provision in the Operating Procedure generally will not apply to a royalty interest. However, it arguably applies if a farmor has the right to convert its ORR to a Working Interest at payout, and Clause 12.02 of the CAPL Farmout & Royalty Procedure is clear on this issue if that document applies. This will probably be academic for a poor well. A cautious farmee would comply with the obligation if payout is anticipated in at least the short to medium term. The converse is also true. If a Party with a convertible ORR would have a ROFR after a payout conversion, that Party might also issue a ROFR. This treatment avoids the allocation issues associated with an asset that includes a well subject to a convertible ORR and other lands earned under the same agreement. The election process typically used in those notices is on the basis of the after payout interests.

ix) Parties that accept a ROFR provision must be aware of the potential consequences of the mechanism if they have a tendency to dispose of a portion of their interest to "partners" who are not recognized in any manner under the Agreement. The obligation to issue the Disposition Notice accrued as of the time of the disposition, and is not contingent on the proposed recognition of the "silent partner". If the original disposition is discovered years after the fact, this could possibly then enable the other Parties to acquire the disposed interest for the original price, subject to an accounting adjustment for revenues and costs since that time.

This was the major issue relating to the 1974 document in Calcrude Oils Ltd. v. Langevin Resources, [2003] A.J. No. 1575 (Alta. Q.B.). In essence, Enerplus purchased an interest from Langevin, where Enerplus had a silent partner that acquired 10% of its interest for a proportionate amount of the purchase price. The silent partner's interest then passed hands several times through transactions that basically involved all of the vendor's assets in Alberta until the ROFR gap was addressed by a purchaser in the chain. Although Enerplus had tried to claim that the interest of a silent partner can be held without attracting a ROFR, the Court disagreed, stating: "…The Defendants have taken the position that there is no obligation to provide a ROFR Notice pursuant to the Farmout Agreement as long as some other Party (not necessarily the vendor) holds the interest in trust following the disposition. This is contrary to the unequivocal words of the CAPL clause 2401 that a ROFR notice must be provided upon any intention to sell an interest. <The Court then quotes the good faith requirement noted in GATX as quoted in the annotations on Alternate 24.01B.>…There is no authority that they are to be relieved from their contractual obligations simply because they arrange for Enerplus to hold the interest in trust. In fact, the authority is quite to the contrary."

The Court then determined that there was no basis to conclude that the plaintiffs would have exercised on the Enerplus transaction with its silent partner, as they did not exercise their ROFR for the original Langevin-Enerplus disposition. Failure to have filed a caveat for the ROFR precluded an award of specific performance. The Court also found that the plaintiffs failed to mitigate their damages by acquiring the interest when the ROFR was eventually offered to them. While the Court found that there was a breach of the ROFR obligation, it found on the facts of this particular case that it was a technical breach and awarded damages of only $1.

<u>CAPL OPERATING PROCEDURE - 2015</u>

Clause 1.01-Market Price Definition, optional sentence: Will ___ Apply
Will Not ___ Apply

Clause 1.01-Production Facility, optional Paragraph (f): Will ___ Apply
Will Not ___ Apply
Estimated cost less than $ _________, if applies

Subclause 3.11C-Required Insurance: Alternate (a) ___ (b) ___

(Consider for special operating areas for which a longer Commencement period is required: **Paragraph 7.01(b) and Subclause 10.03B:** Change reference to 120 days to ___ days.)

Subclause 10.02G-Receiving Party May Not Defer Response: Will ___ Apply
Will Not ___ Apply
Above base of _________ formation, if applies

Subclause 10.04A-Operator for Independent Operation: Alternate (a) ___ (b) ___

Paragraph 10.07A(e)-Penalty Where Independent Well Results in Production: Development Well: _____%
Exploratory Well: _____%

Subclause 10.10A–Definition of Title Preserving Well: ____ days

Subclause 10.13B, optional Paragraph (d): Will ___ Apply
Will Not ___ Apply

Article 21.00–Dispute Resolution: Will ___ Apply
Will Not ___ Apply

Paragraph 21.03(k)–Arbitration Proceedings for unresolved audit exceptions, if Article 21.00 applies:

Will ____ Apply
Will Not ____ Apply
Estimated total adjustment of less than $ ___________, if applies

Clause 22.02-Addresses For Service:

Clause 24.01-Right to Dispose: Alternate A ___ B ___
If Alternate B, the date at which ROFR expires is _____________

Paragraph 24.02(f)–Exception for all Earning Agreements: Will ___ Apply
Will Not ___ Apply