Introduction To 2015 CAPL Overriding Royalty Procedure

This is the second version of the CAPL Overriding Royalty Procedure. The 1997 versions of the CAPL Farmout & Royalty Procedure and the largely parallel Overriding Royalty Procedure became widely accepted in 1998, and have fundamentally changed the way in which our industry has documented earning agreements and royalty agreements.

Users have found that the documents: (i) reduced the cycle time and effort required to complete appropriate documentation; (ii) focused negotiations on key business components of transactions; (iii) streamlined administrative processes, while increasing document and data integrity; and (iv) focused resources on additional value creation opportunities.

This document is intended to cover Overriding Royalties that do not arise from a new earning agreement. These Overriding Royalties would tend to fall within one of the following groupings: (i) an ORR reserved when undeveloped lands are being sold; (ii) an update to an old agreement to modernize the ORR coverage or to address a clarification of interests; (iii) an agreement in which a Party is continuing or validating lands to earn the other Party's Working Interest; (iv) for the "grant" of an ORR on existing lands as a way to obtain funds; or (v) for the "grant" of an ORR by the Royalty Payor to a prospect generator, senior management or a geologist. These Overriding Royalties will often be for <5%.

There are six major objectives associated with this update to the document.

1. Make required modifications while maintaining the integrity and substance of the 1997 document.
   - Changes arising from industry's experiences with that document.
   - Changes requiring a greater scope resulting from evolving business needs.
     - Horizontal Wells and a better platform for shale projects and other projects with high handling costs.
   - Changes required because of completion of the 2007 CAPL Operating Procedure and the 2015 update.
   - Reasonable solutions to reasonably foreseeable problems.
     - Increased breadth and depth of coverage to an extent not feasible with the initial 1997 document.
   - Trend towards "plainer language" drafting style in industry agreements.

2. Create a document that will be widely used in a timely manner after completion.
   - Representatives of major stakeholders (CAPL, CAPLA, CAPPA, PASC, PJVA, Legal and EPAC) involved directly on the project committee to increase alignment and assist in the marketing effort.
   - Ensure that the document is balanced (Royalty Owners and Royalty Payors, large and small companies).
   - Extensive use of annotations to assist users of all experience levels on an ongoing basis.
   - Emphasis on encouraging cross-functional industry comments over the evolution of the document.
   - An attempt to cover a range of typical industry transaction types (80-90% solution), with users expected to modify the document to address exceptions and special needs.
     - Particular care required for "granted" Overriding Royalties.

3. Minimize administrative effort associated with royalty arrangements.
   - Focus the document on the procedural elements that typically do not vary materially in agreements.
     - Shift of new procedural content to the document adds length, but simplifies finalization of Head Agreement.
       - Royalty Allocation Wells, possibility of high handling costs before First Point of Measurement.
   - Companies had historically been saying basically the same thing in a multitude of different ways.
   - Provide a platform to focus on the business issues associated with the particular transaction.
     - Not an attempt to pre-structure the business component of the transaction.
     - Users expected to amend the document to address special needs.
   - Anticipate greater focus on specific facilities and production issues in negotiations.

4. Align document with evolving business needs.
   - Continue to reduce the administrative burden associated with royalty agreements.
   - Identify major improvement opportunities that can deliver desired business results.

5. Simplification.
   - Lever off "plainer language" efforts to simplify presentation and increase clarity for users without sacrificing content.
     - Aggressive editing of the 1997 document and drafts of the update to the CAPL Farmout & Royalty Procedure.
     - Increased use of headings and white space, subdivision of longer provisions.
     - Making cross-references more transparent.
     - Balance simplification with the retention of the required content and options.
       - Options where necessary, but few options to accommodate exceptions to general practices.
       - See the sample one page election sheet included as Addendum II at the end of the document.
   - Incorporate provisions from the 2015 CAPL Operating Procedure to streamline the document.

6. Structure the document to exploit advances in systems technology.
   - Menu format to optimize accuracy of data and streamline data entry for contracts driven land information systems.
   - Structured for possible use with an electronic document preparation tool in due course.

To optimize consistency in handling ORRs, much of this document is taken verbatim from the text and commentary on the CAPL Farmout & Royalty Procedure. The differences typically reflect the likelihood that many of the ORRs to which this document will apply will be relatively small or be in circumstances in which the ORR was "granted", rather than reserved. The more significant differences are identified in the applicable portions of the annotations. (See also Addendum I.)

The explanatory notes reflect primarily observations on the intention and scope of the provisions of the Overriding Royalty Procedure and issues that are expected to be covered in the Head Agreement. The explanatory notes 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 provisions of the document. Although the Overriding Royalty 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 document to address their particular needs for a transaction.

Context-"Reserved" and "Granted" ORRs: The ORR described in the CAPL Farmout & Royalty Procedure is premised on the ORR being "reserved" from the Working Interest originally held by the Farmor at the time of the applicable earning agreement. In other words, the Farmor "held back" the ORR from the Working Interest that the Farmee was to earn under that agreement.

While the Overriding Royalty Procedure will often be used to document the business arrangement relating to a "reserved" ORR, it will also be used to document the Parties' expectations for the handling of "granted" ORRs. A granted ORR may be created by grant with respect to lands held by the Royalty Payor or it may be granted with respect to rights not currently held by it. A "geologist ORR" would be an example of the latter. In that scenario, the Royalty Owner would usually have no pre-existing Working Interest in the applicable Royalty Lands, such that the ORR could not possibly be "reserved" from the Royalty Lands.

To accommodate those transactions, changes were made to such provisions of this document as the definitions of Overriding Royalty, Royalty Lands and Royalty Owner and Clauses 2.01 and 2.07, so that this document could be used for either form of ORR.

The Head Agreement provisions creating a "reserved" ORR will be relatively straightforward because of the similarities to the reservation language used in earning agreements. Greater care must be taken in preparing the Head Agreement associated with a "granted" ORR, though, as noted in the comments below.

- Is the Agreement to cover an ORR already granted, such that the Royalty Lands and ORR are easily described or is the Agreement to cover a particular area within which the ORR may be created and attach to the applicable lands/rights following certain events? Does it attach to all zones or only those that have a cause and effect relationship to the services provided? Users would need to be very clear what lands/rights are to be encumbered, what events trigger the creation of the ORR and the date that the ORR takes effect. Is the intention that the ORR is based on whatever percentage of Working Interest is held or initially acquired by the Royalty Payor or is there another basis? To protect itself, for example, the Royalty Owner would presumably want it to attach to Working Interests acquired by the Royalty Payor and any of its Affiliates, rather than just the Royalty Payor.

- What happens to the ORR if the Royalty Payor assigns a portion of its Working Interest to another company in a *bona fide* transaction? Is the granted ORR linked only to the Working Interest of the Royalty Payor and its Affiliates? This is potentially relevant for ORRs created for employees because of the adverse impact these ORRs could have on the ability to optimize value for the Royalty Payor's shareholders in certain circumstances.

- What are the Parties' expectations if an Operating Procedure applies to the Working Interests, the granted ORR is not borne for the Joint Account and the Royalty Payor does not wish to participate in a proposed well or it would prefer to surrender its Working Interest in certain Royalty Lands? Again, there may be a different answer if the ORR has been granted to employees.

Provisions expected to be included in the Head Agreement and customized to the particular transaction follow:

Provision	Annotation with sample precedent
Def'ns of Royalty Payor and Royalty Owner	Clauses 1.04 and 1.03
Title Administrator	Clause 6.01
Schedule "A" (Royalty Lands, current Royalty Owner interests etc.)	------------
Well Information Requirement Schedule, if applicable	------------
Special provisions (e.g., any abandonment rights, impact of non-participation by Royalty Payor)	Not addressed - custom provisions.

Clause 1.01–General: i) Many of the definitions from the 2015 CAPL Operating Procedure are incorporated by reference in Clause 1.02. (See the annotations to that document for insights on those definitions.)

ii) The Overriding Royalty Procedure definitions are expected to be used in the Head Agreement. Something like the following should be included in the definitions Clause of the Head Agreement: *"Each capitalized term used in this Head Agreement will have the meaning given to it in Clause 1.01 or 1.02 of the Overriding Royalty Procedure. In addition:"* These definitions are those noted above and any other definitions that are required for the transaction.

Overriding Royalty: The "within, upon, under or attributed to the Royalty Lands" and "reserved by the Royalty Owner" references reinforce the Parties' intention that the ORR be an interest in land. The "or granted to" reference deviates from the CAPL Farmout & Royalty Procedure provision by accommodating "granted" ORRs. A Royalty Owner should put a caveat on title whenever possible.

Reserved Formations: This provision will typically apply if rights are initially reserved from the Royalty Lands or the Royalty Payor's ORR obligation is limited to select formations. (See also Article 9.00.)

Royalty Lands: i) The Royalty Lands comprise all lands then subject to the ORR. This definition varies significantly from the definition in the CAPL Farmout & Royalty Procedure, so that it can apply to "reserved" ORRs, "granted" ORRs for which the Royalty Lands are known and "granted" ORRs that may later be created. While not addressed initially in the Land Schedule because the obligation has not yet attached, the latter could become Royalty Lands on the basis and time prescribed by the Head Agreement. The Parties to an Agreement involving such a granted ORR would be prudent to be clear about the notification or documentation process to be used when their Agreement caused the granted ORR to attach to the applicable Royalty Lands.

ii) Note the linkage of the ORR to the Title Documents relating to the applicable Royalty Lands. This mitigates the potential for a Royalty Payor to find itself with the unintended consequence of a perpetual obligation for certain described lands, rather than the lands subject to a particular Title Document during the period in which it remains in effect. This is a potential problem with older agreements that used unqualified references to covenants that "ran with the lands" in circumstances in which the "lands" were not linked to the residual term of the applicable tenure.

Royalty Well: The definition includes wells located on the Royalty Lands and wells drilled off the Royalty Lands under an arrangement that includes Royalty Lands, such as a pooling.

Title Documents: i) A Royalty Payor should be very careful in describing the interest to which a granted ORR will attach. This is particularly important if the Royalty Lands are in an area that includes freehold rights if it is possible that the Royalty Payor holds or could acquire fee interests. Risk on the acquisition of fee interests and with respect to any subsequent acquisition of ORR interests by the Royalty Payor could be mitigated by linking a granted ORR to the Royalty Payor's Working Interest.

ii) Whether a Title Document is a replacement can be a question of fact and law. 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.

Clause 1.02-General: i) The incorporation of the Operating Procedure provisions anchors the Overriding Royalty Procedure to familiar and accepted industry standards. It also ensures that there will be consistency in interpretation of these terms throughout the document without the duplication that would occur in the majority of earning transactions.

ii) Although some users may still prefer the 1990 CAPL Operating Procedure during the early stages of industry's transition to this version of the Overriding Royalty Procedure, any concerns with the 2007 or 2015 Operating Procedure would probably pertain to provisions other than those presented in this list. Even if that assumption were inaccurate, it would be easy for users to address specific concerns by deleting the specific provisions to which the concerns pertain.

Facility Fees: i) This definition is used when addressing the Royalty Owner's responsibility for product enhancement costs/deductions after the First Point of Measurement under Subclauses 2.04C and 2.05B. However, the Facility Fees are not applied as a deduction against the proceeds payable to the Royalty Owner for gas and associated substances if the Parties had selected the "no deductions" option in Alternate 2.01A(b)(2).

ii) Paragraph (b) eliminates the need to negotiate the details of a formula, such as JP-95 or JP-05, when the Agreement is negotiated. The Royalty Payor may 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? Under Paragraph (a), a Royalty Payor can deduct processing fees paid to third parties, which would probably be based on the "Jumping Pound" principles. While ultimately a negotiable item, Royalty Payors would typically expect a similar rate of return on owned facilities for handling ORR volumes.

iii) Operating cost and return on capital components are referenced 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. The inclusion of a specified negotiated return might be more attractive. However, certainty on the calculation of the capital base would be required to do this, and this 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 the Royalty Payor's facility through inclusion of something such as *"a capital rate of _______ ¢/10³m³ plus the actual cost of operating experienced by the operator of the facility."* This is really no different from the Royalty Payor's negotiation of a specified fee for use of a Royalty Owner's plant as part of some transactions. Subparagraph (b)(i) has been included to encourage the Parties to complete specific agreements on this issue.

v) Although the JP-05 methodology is referenced, the provision evolves to the then most current industry recognized successor.

vi) Disputes can ultimately be referred to the dispute resolution provisions in Clause 8.01. The possible use of arbitration therein is designed to encourage Parties to negotiate a resolution of any disputes without facing an uncertain arbitration outcome.

Facility Usage: Facility Usage is the use of any facilities not included within "Equipping Costs" to increase the value of production from Royalty Wells (e.g., processing of gas) and to deliver it to market. Transportation costs required in the determination of a Market Price under Clause 1.02 are excluded, to avoid a double recovery. The definition is linked to the Facilities Fees definition.

First Point of Measurement: This definition is comparable to the "Royalty Determination Point" definition in the 1997 document. It only applies in Article 2.00 for the handling of ORR volumes. There are circumstances in which secondary treatment is required.

Horizontal Well: The definition of Horizontal Well has been modified to be clear that each Horizontal Leg of a multi-pronged Horizontal Well is treated as a separate Royalty Well for purposes of Article 2.00.

Market Price: The 1997 document supplemented the "market price" definition in the 1990 CAPL Operating Procedure by including a proviso that required dispositions of ORR gas volumes to be managed on the basis of a specific one-month AECO-C index price, as published in the Canadian Gas Price Reporter. The 1997 document offered excellent protection against the abuse scenario. However, users typically did not honour the specific requirements of the provision, largely because Production Accounting personnel did not conveniently have access to the marketing information contemplated in the proviso. Royalty Owners have typically only applied the proviso literally if they regarded the pricing used by the Royalty Payor for calculation of the ORR as unreasonable.

The "Market Price" definition from the Operating Procedure still provides significant protection against notional allocations of unfavourable sales arrangements, but in a much less prescriptive way. The focus in the Operating Procedure definition is on including appropriate protections against the abuse scenario, without prescribing a particular price if the Party managing production volumes is acting reasonably. To simplify administration, the definition includes an optional sentence that allows the Royalty Payor to use corporate pool based pricing for its sales of equity volumes in the jurisdiction in which the Royalty Lands are located.

Spacing Unit: i) The CAPL Farmout & Royalty Procedure includes a definition of Spacing Unit primarily for the purpose of describing earning. In fact, a Spacing Unit is a multi-dimensional concept under the Regulations (i.e., area, formation, substance and, if special spacing could apply, time). As a consequence, the Operating Procedure definition is incorporated for this document.

ii) The qualification was added to the 2015 document because of the potential application of Clauses 2.02 and 2.03 to a Royalty Allocation Well for which the Royalty Lands comprise less than the full area required under the Regulations for a vertical well. To illustrate, assume that the Royalty Lands are Section 1 and N2, that a Royalty Allocation Well targeting gas is drilled on S1 and S2, that 70% of the Royalty Length is on Section 1 and 30% on Section 2 and that Alternate 1 of the definition of Royalty Allocation Ratio applies. In that case, 70% of the production would be allocated to Section 1 and 30% allocated to Section 2, with that 30% typically further allocated under Clause 2.02 between the Royalty Lands (50% of 30%) and the other lands (50% of 30%).

Subclause 3.10B: This provision of the Operating Procedure has been amended. The Operator is not required to consult with a Royalty Owner holding a non-convertible ORR when submitting a continuation application unless there are Reserved Formations with respect to the applicable lands. However, the Operator would still be required to forward copies of material correspondence pertaining to the maintenance of the Title Documents. This proviso and some of the other modifications in this Clause are premised on the presumption that a Royalty Owner of a non-convertible ORR has limited strategic interest in the property. This assumption will not always be accurate, such that there will be circumstances in which the Royalty Owner would wish to override this proviso.

Clause 3.11: The Operating Procedure insurance provision has not been included because of the typical nature of the ORRs governed by this document. Similarly, the document does not require the Royalty Payor to obtain "control of well" or "comprehensive general liability" insurance. See the corresponding annotation in the CAPL Farmout & Royalty Procedure if this type of coverage were being considered for the Head Agreement.

Article 7.00: This Article is not incorporated by reference. This reflects the degree to which technical personnel rely on well requirement sheets in practice. Well information requirements would be a Schedule if Paragraph 3.01A(b) were selected.

Article 18.00: The reference to Clause 18.01 was amended in the 2015 document relative to the change to Clause 1803 in the 1997 CAPL Farmout & Royalty Procedure. The identified modification is now optional. If selected, the Working Interest owners do not have a confidentiality obligation to any Royalty Owner Party holding only a non-convertible Overriding Royalty. As noted above, this is based on the presumption that a Royalty Owner with a non-convertible ORR does not regard the applicable lands as strategic. While this presumption is normally valid, there will be many circumstances in which it is not, such that this modification should not apply. The Royalty Owner may reasonably argue that the confidentiality obligation should be mutual if, for example, the Royalty Owner retains other undeveloped lands near the Royalty Lands, particularly if the wells are more exploratory in nature.

Clause 22.02: The Parties' addresses for service need to be included in the Head Agreement or in the Schedule of elections.

Clause 24.03: This has been included to ensure that the Royalty Payor does not bear an undue administrative burden if the Royalty Owner assigns the ORR to multiple assignees or *vice versa*.

Clause 1.03: i) This Clause only applies if the Royalty Owner is comprised of more than one Party. If it applies, the Royalty Owner might be defined as *". . A, B and C as to respective X%, Y% and Z% interests"*. Clearly expressing the relative sharing between the Royalty Owner Parties adds significant transparency for users. There may also be instances in which it is preferable to amend the end of the Clause to something like: *".. . proportionately to the Royalty Owner Parties as follows:…..".*

ii) Royalty Owner and Royalty Payor are collective definitions. References such as the Royalty Owner Party differentiate between collective rights and those that accrue individually to each applicable Party comprising the Royalty Owner or Royalty Payor.

iii) The provision would be more complicated if the Royalty Owner Parties or their interests varied in the Royalty Lands.

iv) This Clause will also apply if the Royalty Owner is comprised of a single Party that subsequently disposes of a partial interest.

v) This Clause does not include the designated representative mechanism used in Clause 1.04. All elections made by the Royalty Owner, such as the taking of ORR production in kind, are individual elections. Since Royalty Payors have a legitimate concern about the administrative burden potentially associated with partial dispositions of the ORR to multiple assignees, Clause 24.03 of the Operating Procedure has been incorporated by reference in Clause 1.02.

Clause 1.04: i) This Clause only applies if the Royalty Payor is comprised of more than one Party. Annotations (i)-(iii) for Clause 1.03 apply equally to this Clause.

ii) Paragraph (a) states that the obligations of the Royalty Payor Parties are joint and several, such that the Royalty Owner can seek performance of the Royalty Payor's obligations from any particular Royalty Payor Party (e.g., the most financially viable Royalty Payor Party, even if that Royalty Payor Party has a relatively small share of the total Royalty Payor interest). The Paragraph is based on the principle that the Royalty Payor Parties choose their own co-venturers/assignees, not the Royalty Owner.

A Royalty Payor that wishes to share the risk under the Agreement by assigning a partial interest in the transaction needs to consider carefully the financial viability of its proposed assignees. This comment applies equally to a potential assignee considering acquisition of a partial interest from any existing Royalty Payor Party.

iii) Paragraph (b) allows the Royalty Owner to deal solely with the designated representative of the Royalty Payor for many matters arising under the Agreement. This is because of the need for certainty in communication between the Royalty Payor Parties and the Royalty Owner. This ensures, for example, that the Royalty Owner does not need to check with each Royalty Payor Party if the Royalty Payor's designated representative elects to surrender.

iv) The Royalty Payor Party designated as the representative in the Head Agreement will typically act as Operator for the purposes of the provisions incorporated from the Operating Procedure in Clause 1.02. The potential liability of the Royalty Payor representative to the other Royalty Payor Parties for the manner in which it fulfills these responsibilities is governed by the agreement that applies to the Royalty Payor Parties (i.e., their own Operating Procedure).

v) Item (b)(iii) differs from the CAPL Farmout & Royalty Procedure, as the Royalty Payor designated representative can be changed by notice, rather than through a consent not to be unreasonably withheld mechanism.

Clause 1.05: This Clause protects the Parties against changes to the standard form that were not identified when the document was prepared. It is necessary because of the possibility that Parties will prepare their document electronically, rather than by attaching a CAPL watermark copy. It largely mirrors Clause 1.15 of the 2007 and 2015 CAPL Operating Procedures, and 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 and the PetroDocs version of the 1990 CAPL Operating Procedure.

In essence, it ensures that changes not identified in the Overriding Royalty Procedure, the Agreement or a Schedule of elections and modifications are not effective. The CAPL standard form would apply as if the applicable changes were not made.

Article 2.00: The starting point in understanding an Overriding Royalty is realizing that there are two major types of ORRs-those that are "reserved" and those that are "granted". The Overriding Royalty to which the Farmout & Royalty Procedure applies is always a "reserved" ORR, as the ORR has been reserved by the Royalty Owner from the Working Interest being earned by the Royalty Payor from the Royalty Owner under the earning arrangement. The CAPL Overriding Royalty Procedure is unlikely to be used in conjunction with a new farmout, but can be used in a wide range of circumstances for either form of ORR. It could be used, for example: (a) for a reservation of an ORR by the Vendor on a sale transaction; (b) in cleaning up an old outstanding royalty agreement in which the ORR had been reserved; (c) updating to a more modern document an old royalty agreement in which the ORR had been reserved; (d) if a Royalty Payor is choosing to grant an ORR on an interest it already owns as a way to obtain funds; or (e) for the grant of an ORR by a Royalty Payor on lands that it has not yet acquired (e.g., an ORR created in favour of a geologist, consultant or agent in return for work on a prospect or in bringing a project idea to the Royalty Payor). As noted above, the interest in land of the Royalty Payor is often not held by it at the time of a "grant" of an ORR to the Royalty Owner.

It is important to understand the difference between the two types of ORR when considering the critical question of whether the applicable ORR is an interest in land and how best to protect the interest of a Royalty Owner. Being able to characterize the ORR as an interest in land affords much greater potential protection at law relative to third parties than would be the case for any ORR that is not regarded as an interest in land, particularly relative to third parties that acquire the applicable Working Interest through bankruptcy proceedings of the Royalty Payor.

The issue of whether an ORR can be an interest in land has been addressed over many years in a series of court cases and various articles. (See, for example, St. Lawrence Petroleum Limited et al. v. Bailey Selburn Oil and Gas Ltd and H.W. Bass and Sons Inc., [1963] S.C.R. 482 (S.C.C.), affirming (1962), 35 D.L.R. (2nd) 574 (Alta. S.C., App.Div.) and [1961] A.J. 19 (Alta. S.C.) (a case concerning a share of "net proceeds" associated with a participation agreement); Emerald Resources Ltd. v. Sterling Oil Properties Management Ltd. (1969), 3.D.L.R. (3d) 630 (Alta. S.C., App. Div.), affirmed (1970), 15 DL.R. (3d) 256 (S.C.C); Saskatchewan Minerals v. Keyes, [1972] S.C.R. 703 (S.C.C.), reversing (1970), 12 D.LR. (3d) (Sask. C.A.) that reversed in part [1968] S.J. No. 173 (Sask. Q.B.); Bensette and Campbell v. Reece, [1973] 2 W.W.R. 497 (Sask.C.A.), reversing (1969), 70 W.W.R. 705 (Sask. Q.B); and Vanguard Petroleums Ltd. v. Vermont Oil & Gas Ltd. et al. (1977), 72 D.L.R. (3d) (Alta. S.C., T.D.)) While those earlier authorities had suggested that an ORR could possibly be an interest in land in some circumstances, the ORRs that were the subject of those cases were not strong enough to be an interest in land.

The leading case on point is Bank of Montreal v. Dynex Petroleum Ltd., [2002] 1 S.C.R. 146 (S.C.C.), affirming [2000] 2 W.W.R. 693 (Alta. C.A.) that reversed [1997] 6 W.W.R. 104 (Alta. Q.B.). It offered legal clarity about whether an ORR could be an interest in land. The historical common law outcome was that an ORR could never be an interest in land because the ORR was not being derived from the "corporeal hereditament" (i.e., fee title to the land itself), but from the right of the Working Interest owner to exploit the land through a type of "incorporeal hereditament" known as a profit à prendre. The Supreme Court of Canada and the Alberta Court of Appeal recognized the commercial practices in the industry, and determined that it was reasonable for an ORR to be an interest in land if that is what was intended in an agreement. It then directed the case to be returned to trial to determine if the ORRs in question were interests in land. That Court ultimately determined that it was not the intention under the applicable royalty agreements to create an interest in land (Bank of Montreal v. Dynex Petroleum Ltd. (2003), 1 C.B.R. (5th) 188 (Alta.Q.B.).

The net effect of the Supreme Court of Canada decision is that an ORR can be an interest in land if: (a) "the language used in describing the interest is sufficiently precise to show that the parties intended the royalty to be a grant of an interest in land, rather than a contractual right to a portion of the oil and gas substances recovered from the land; and (b) the interest, out of which the royalty is carved, is itself an interest in land."

Several key observations arise from this decision. Firstly, it is clear that a "granted ORR" that applies to rights not then held by the Royalty Payor cannot be an interest in land, as the Royalty Payor granting the ORR did not then have a Working Interest that was an interest in land. See, for example, In the Matter of Promax Energy Inc., [2003] A.J. No.1718 (Alta. Q.B.). It pertained to an insolvency in which the Court held that the ORR respecting lands within an AMI was a contractual right to a royalty on production if and when acquired by the Royalty Payor, such that the ORR would not apply to lands already held by the successor in interest to the Royalty Payor or later acquired by that successor in circumstances in which it did not novate into the royalty agreement. (Q-Can the Parties lessen the "granted ORR" risk by entering into a separate royalty agreement or other form of confirmation from time to time after there have been acquisitions of Working Interests in the applicable lands by the Royalty Payor?) Secondly, the onus is on the Royalty Owner to register a caveat respecting its interest in land to optimize its priority relative to third parties. Thirdly, there is still significant residual uncertainty as to whether any particular ORR will be regarded as an interest in land. The determination is made on a case-by-case basis in circumstances in which there has not yet been any decision of a court to offer guidance about whether the language in the Overriding Royalty Procedure respecting a "reserved ORR" is sufficient to meet the Dynex test.

This Article and the definition of Overriding Royalty in the 1997 and 2015 documents have been structured to attempt to reinforce that a "reserved ORR" is an interest in land. The documents give a Royalty Owner more of an "active" interest than the mere receipt of cash proceeds. The CAPL provisions include, for example: (a) a reference in the definition of Overriding Royalty that it applies to

Petroleum Substances "within, upon, under or attributed to the Royalty Lands"; (b) an initial statement in Subclause 2.01A that the ORR is an interest in land (2015 document only); (c) a reservation of the ORR out of the Working Interest (the reservation language in the Head Agreement); (d) a presentation of the ORR in the context of production volumes (Subclause 2.01A); (e) consent requirements for certain types of production allocation arrangements involving the Royalty Lands (Subclause 2.02B); (f) the right to take in kind and the creation of an agency relationship insofar as the Royalty Owner does not do so (Clause 2.04); (g) a statement that deductions are described as cash adjustments for convenience of record keeping with no intention to alter the status of the ORR as an interest in land (Subclause 2.05E); (h) the creation of a royalty lien and (in the 2015 document) charging language against the encumbered Working Interest, with an express statement in both versions of the document that the ORR and the lien are interests in land (Clause 2.07); (i) possible reversionary rights upon expiry or surrender (Clause 2.09); (j) potential rights to well information (Clause 3.01); (k) rights respecting certain dispositions (Clause 5.02); and (l) the right to enforce a royalty lien (Clause 7.01). The same principles might also apply to a properly constructed "granted" ORR on existing rights.

Clause 2.01: i) The calculation of the ORR on a well-by-well basis ensures that the Royalty Payor cannot apply costs from one well to another well to reduce the Royalty Owner's ORR. The calculation is subject to Subclause 2.02C and Clause 2.03, which address the special treatment for production allocated under a pooling, unit or a royalty allocation respecting certain Horizontal Wells. This interrelationship is emphasized in Subclause A because it may not be appreciated fully by personnel working with ORR calculations.

ii) The ORR for crude oil might be a flat royalty (Alternate (a)(1)) or a sliding scale royalty, such as the typical 5-15% royalty (Alternate (a)(2)). (The sliding scale alternative had not been included in the 1997 document because of the assumption about the magnitude of ORRs likely to be governed by that document.) The percentages in Alternate (a)(2) have been left blank, to be negotiated for each transaction.

iii) This Alternate uses a metric calculation. The metric equivalent of the typical 1/150 oil ORR is 1/23.8365, which is sometimes replaced by 1/24 for simplicity. Only the denominator is included in the blank because "1/" is inherent in the "divided by" reference.

iv) Audit experience has shown that calculation errors are often made when using the sliding scale method. These include forgetting that a sliding scale applies if the production has been at a constant rate for long periods, unit allocations and determinations involving less than a 100% Working Interest (i.e., using the net barrels rather than gross production in the formula). It is also important to recall that the calculation is made after removal of basic sediment, water and other applicable impurities.

v) If a Royalty Well produces oil from more than one zone, the sliding scale is typically calculated separately for each zone. This is the way in which the Alberta Crown applies its lessor royalty. The exception is to take into account commingling authorized pursuant to the Regulations. (See, for example, Sections 3.050 and 3.051 of the *Oil And Gas Conservation Rules* (Alberta).) The definition of Horizontal Well in Clause 1.02 has also been modified so that each Horizontal Leg is treated as a separate well for this purpose.

vi) The application of the floor and cap thresholds is always on the 100% ORR calculation. The ORR is then prorated under the last paragraph of Subclause A to the Royalty Payor's encumbered Working Interest, and the wording of that Paragraph has been adjusted in this document (relative to that in the CAPL Farmout & Royalty Procedure) to accommodate both "reserved" and "granted" ORRs. Particular care must be taken in describing an ORR accruing on less than a 100% Working Interest. To illustrate, would accounting and technical personnel interpret a 3% ORR based on a 50% interest as a 6% ORR based on 100% that has been presented as a net amount or as a net 1.5% (3% of 50%)? A sample that illustrates a preferable presentation of such a burden is: "ORR of 7.5% based on 50% of production (net 3.75%) accruing to A and B in respective 75% and 25% shares and payable by X and Y in respective 65% and 35% shares."

There are also potential calculation issues. Assume, that the Royalty Payor holds a 50% Working Interest, that the well is producing $20m^3/d$ of oil and that the traditional sliding scale ORR applies. The resultant ORR would be the 15% maximum (600/23.8365), and then prorated to 50%, or a net 7.5%. Erroneously netting the production before the 100% calculation would give an ORR of $600m^3$ X 50%/23.8365, or a net 12.6%-a large difference.

vii) The ORR in Paragraph A(b) applies to gas and associated substances. This includes condensate (both field and extracted), NGLs and solution gas.

viii) The administrative burden associated with gas ORRs is high. The 1997 document introduced an option in Subparagraph (b)(2) to structure the ORR on gas and associated substances as a negotiated percentage free of all Facility Fees if the Royalty Owner does not take in kind. This would require the Royalty Payor to pay all of the product enhancement costs to make the ORR share merchantable and to deliver it to market, subject to two important qualifications. The first is that this election does not affect the adjustments for transportation expenses in calculating a Market Price under Clause 1.02, as the definition of Facility Usage excludes those adjustments. The second is that the Royalty Owner bears its share of any enrichment costs under Subclause 2.05D.

ix) The Royalty Owner would generally "compensate" the Royalty Payor for the assumption of those costs through a negotiated ORR lower than would be the case if the ORR were taken in kind. (The major exception to that general rule would be gas to be taken directly from the wellhead to the sales line with minimal, if any, product enhancement.) The right to take in kind has been retained in this Alternate to protect the Royalty Owner with respect to a high gas price environment and against abuse (e.g., the Royalty Payor selling at the wellhead before any meaningful product enhancement costs were incurred). (The Royalty Owner would assume responsibility for its own product enhancement costs under Subclause 2.04C if it took in kind.)

Subparagraph (b)(i) basically provides the same outcome as the custom "no deductions ORR" provision included in some agreements to manage deductibility of product enhancement costs, with three important exceptions. The first is that it ultimately only applies to Facility Fees incurred through the outlet of a gas plant, as transportation expenses thereafter are captured as revenue adjustments under the Market Price definition. The second is that the calculation applies after any adjustment for enrichment costs under Subclause 2.05D. The third is that the typical custom industry provision effectively eliminates the right to take in kind. The motivation to take in kind is low if a Royalty Owner would receive the same percentage of production volumes while being required to assume product enhancement costs after the First Point of Measurement. Royalty Owners that include such a custom provision can achieve the same basic protection against high deductions if they do not take in kind by selecting this Subparagraph.

This Alternate also positions the Royalty Owner to participate more fully in the upside if gas prices increase significantly, assuming volumes and infrastructure logistics warrant taking in kind. (This presumes that product enhancement costs are relatively flat.) The different percentage contemplated for the take in kind component also reinforces the Parties' intention that they would have used a higher percentage if they intended that there be any deductions for Facility Fees if the Royalty Owner did not take in kind-something that Parties including their own custom drafted "no deductions" restriction should state in their Clause.

While this option has administrative benefits, it has some potential disadvantages. It may require front-end effort to negotiate, particularly in the initial stages of use. It also may create some distortions over time if there are large price changes for a long period. The right to take in kind would help a Royalty Owner manage the impact of a large price increase, though.

x) The ORR is described as a percentage of production of Petroleum Substances from the Royalty Lands, not a percentage of the proceeds of sale of production received by the Royalty Payor. This reinforces the categorization of the ORR as an interest in land.

xi) Flaring in excess of levels permitted under the Regulations is not addressed in this provision. It is unlikely to be a significant issue in practice, and is already captured by the general duty to conduct Operations in compliance with the Regulations. (See the incorporation of Clause 3.04 of the Operating Procedure in Clause 1.02.)

xii) Subclauses 2.01C and D were introduced in the 2015 document because of the possibility of the use of hydrocarbons in conjunction with fracture stimulation programs or a storage project. Any such injected substances recovered from a Royalty Well are not regarded as production. This creates a similar outcome as is seen for enrichment expenses under Subclause 2.05D.

Subclause 2.02A: i) This is based on the pooling clause in the CAPL P&NG Lease, and is subject to the terms of the applicable leases. Although a lease will usually permit the Royalty Payor to pool to complete a Spacing Unit, this is not always the case.

ii) Subclause A provides general authority for acreage based poolings of a Spacing Unit, subject to a qualification introduced in the 2015 document that the basis for the pooling is not unreasonable. A pooling may be on another basis if appropriate in the circumstances, in which case Subclause B will apply. The Royalty Payor may also be in breach of a duty to act in good faith if it proceeds with an acreage based pooling if it is clear that there would be an inequitable allocation of production. (See Mesa Operating Ltd. Partnership v. Amoco Canada Resources Ltd. (1992), 129 A.R. 177 (Alta. Q.B.), affirmed (1994), 19 Alta. L.R. (3rd) 38 (Alta. C.A.).) In that case, the operator had pooled, on an areal basis, the north half of the section in which it held a 100% unencumbered interest with the south half of the section that was subject to the ORR and held with other Working Interest owners in circumstances in which it was apparent that the reservoir was entirely or substantially under the south half of the section.)

Subclause 2.02B: i) Subclause B attempts to balance the needs of the Parties. The Royalty Owner wishes to ensure that the resultant allocation of production will not be unreasonable. The Royalty Payor, on the other hand, wishes to ensure that the Royalty Owner cannot unduly constrain development of the Royalty Lands. The consent not to be unreasonably withheld mechanism, with a 20 Business Day response window, has therefore been used. The term "combination" is used in Subclause B because of the use of the terms "block" and "project" in the *Oil And Gas Conservation Act* (Alberta) and the associated Regulations.

ii) The 2015 document requires a Royalty Owner that is not prepared to consent to a proposal under Subclause B to identify the basis for its withholding of consent. A Royalty Owner that intends to withhold its consent must understand the potential risk to it if this frustrated the transaction and there were a subsequent determination that the consent had been unreasonably withheld.

Subclause 2.02C: i) Assume that 2 Lsds of the Royalty Lands are pooled with another 2 Lsds to complete an oil Spacing Unit on a simple areal 50-50 basis. If the well is producing at $8m^3/d$ and the traditional 5-15% formula applied, the resultant ORR under Subclause C will be 10.06% (240/23.8365) x 50%, or a net 5.03%.

ii) Assume that $10m^3/d$ of oil is allocated to a quarter section tract of Royalty Lands under a unit. If the traditional sliding scale applies on a 100% interest, the resultant ORR would be 12.6% (300/23.8365). This allocation would typically still apply if a well on these lands actually produced at a higher or lower rate. Production is allocated to unit lands on the basis prescribed by the unit, irrespective of actual production from a particular tract.

iii) The interrelationship of the Overriding Royalty Procedure and a unit agreement and the impact of a unitization on the calculation of a sliding scale ORR are clear in this document. This will not always be the case in older agreements that do not use the CAPL document, however. The starting point in understanding the potential issue is the realization that unit agreements do not modify the manner in which ORRs are calculated in an underlying agreement in the absence of provisions in that agreement or other agreement by the royalty holders. See, for example, Alminex Ltd. v. Berkley Oil & Gas Ltd., [1972] 6 W.W.R. 412 (Alta. S.C., App. Div.), affirming [1971] 4 W.W.R. 401 (Alta S.C.), appeal dismissed [1975] 1 S.C.R. 1262 (S.C.C.) and Home Oil Co. v. Page Petroleum Ltd., [1976] 4 W.W.R. 598 (Alta S.C.). The sliding scale ORR in each of those cases was not linked to production from any individual well. As a result, the Court found the sliding scale to be based on production volumes from the applicable Royalty Lands, not individual wells or allocations to individual tracts. See also Vandergrift et al. v. Coseka Resources Limited et al. (1989), 95 A.R. 372 (Alta. Q.B.), in which the ORR holder unsuccessfully attempted to extend its ORR for a well on the ORR lands to all wells in a gas block that had been created to avoid the imposition of a significant off-target production penalty against the ORR well.

iv) Also see the annotations on Clause 2.01 respecting common calculation errors.

Clause 2.03: It is increasingly common for Horizontal Wells to be drilled across both Royalty Lands and other lands. This is particularly the case as advances in technology and the proliferation of shale projects see more long reach wells being drilled.

The definition of Allocation Ratio includes two Alternates for the determination of the ORR that will be allocated to the Royalty Lands if there is such a Royalty Allocation Well. One methodology (Alternate 1) basically uses the ratio of the Royalty Length to the well's Total Horizontal Length. That Alternate is generally well aligned with the approach used by Alberta in Production Allocation Unit Agreements for an allocation of production between Crown and freehold rights penetrated by a Royalty Allocation Well. The other methodology (Alternate 2) was included primarily to accommodate the production allocation approach used by the Saskatchewan Crown for a similar allocation. The current Saskatchewan methodology for those lessor royalty allocations is based on the acreage within a cigar shaped area around the horizontal portion of the well. Alternate 2 aligns directly to the approach prescribed by the Regulations of the applicable jurisdiction for the volume allocation for Crown royalty purposes, with a consequence that the methodology could change over time. Although the allocation dictated by Alternate 1 may prescribe a different outcome than that under the applicable Crown process, it is important to recall when choosing the applicable Alternate that there is no requirement that the contractual outcome between the Royalty Owner and the Royalty Payor must be the same as the lessor arrangements in the applicable jurisdiction. In other words, there is actually no requirement to include Alternate 2 to align with the regulatory approach, something that could be relevant to the Parties if there were no need to allocate production between Crown and freehold rights.

Allocation Ratio: i) The Allocation Ratio under Alternate 1 is the ratio of the Royalty Length of a Royalty Allocation Well to its Total Horizontal Length based on the As Drilled Survey for the well. To illustrate, the Allocation Ratio for a Royalty Allocation Well with a Royalty Length of 600m out of a Total Horizontal Length of 2000m would be 30%.

As noted in the definition of Toe, the Allocation Ratio for a Royalty Allocation Well will be adjusted if a portion of the horizontal segment of the well is permanently plugged back or cemented off prior to putting the well on initial production. No further adjustments are made to the Allocation Ratio over the life of the well, though, if productivity of the Royalty Allocation Well changes over time or further plugging back activities are conducted in the horizontal portion of that well. (See also Subclause 2.03D.)

ii) Under Alternate 1, the Allocation Ratio is not subject to adjustment if a different allocation methodology would be applicable to lessor royalties under the Regulations. Parties wishing to obtain that alignment would select Alternate 2.

iii) The calculation is complicated if a further allocation is required within a portion of the Spacing Unit(s) for the Royalty Allocation Well under Clause 2.02 because the Royalty Lands comprise only a portion of the applicable area. A Horizontal Leg of a gas well on Sections 1 and 2 in which the Royalty Lands comprise only S1 and S2 would require an allocation for each Section, so that the allocation within each of the Sections could then be made under Clause 2.02.

iv) Parties might prefer to use a more complex calculation in some circumstances by linking the calculation to the number and location of the staged fracs in a Royalty Allocation Well or forecast relative production if there are known differences across the well. Those methodologies would be situation dependent, so they were not appropriate for a document of general application. Care must be taken, though, if the Parties are using a methodology that could be manipulated, it is not readily transparent or it could see changes over time (e.g., a Recompletion with additional fracs). The Parties would also need to be aware that this type of allocation would be inconsistent with the methodologies applied by regulatory authorities in their Production Allocation Unit Agreements.

As Drilled Survey: An As Drilled Survey provides a clear illustration of all of the elements needed to determine the Allocation Ratio. It can be created by a surveyor in conjunction with drilling or can be created from the "final survey listing report" that is part of the well data normally provided to the well participants/Royalty Owner and regulators after the drilling of a Horizontal Well. That report includes the "actual wellpath report", which has the co-ordinates followed by the drillbit.

Heel: i) In most cases, the Heel will be the same as the Intermediate Casing Point, but this will not necessarily be the case. The definition includes flexibility for the circumstances in which the intermediate casing is set in the target formation, it is set above the target formation or there is no intermediate casing at all. Parties that know that they will set intermediate casing in the target formation at a depth well above the true horizontal penetration should modify the definition accordingly for their transaction.

ii) Special circumstances in which the Heel and Toe definitions do not offer a suitable outcome would need to be addressed by the Parties on a custom basis in the context of their particular transaction. The overall intention is that the Royalty Length is limited to the initial productive portion of the wellbore. Modifications would be required for a particular Royalty Allocation Well in practice if, for example, the "Heel" were at a location from which the Farmee would be precluded from producing under the Regulations.

Royalty Allocation Well: i) This is a well in which the horizontal portion of the well penetrates both a Spacing Unit that includes Royalty Lands and other lands. (The Spacing Unit reference is included because of the possibility that a further allocation may be required within the Spacing Unit under Clause 5.02 due to a pooling within that Spacing Unit.)

ii) Note the reference “a Spacing Unit that includes Royalty Lands” and the corresponding qualification to the definition of Spacing Unit. These were included because of the potential application of Clauses 2.02 and 2.03 to a Royalty Allocation Well for which the Royalty Lands comprise less than the full area required under the Regulations for a vertical well on the location. To illustrate, assume that the Royalty Lands are Section 1 and N2, that a Royalty Allocation Well targeting gas is drilled on S1 and 2, that 70% of the Royalty Length is on Section 1 and 30% on Section 2 and that Alternate 1 of the definition of Allocation Ratio applies. In that circumstance, 70% of the production would be allocated to Section 1 and 30% allocated to Section 2. That 30% would then typically be further allocated under Clause 2.02 between the Royalty Lands (50% of 30%) and the other lands (50% of 30%).

Royalty Length: This is the actual length of the Royalty Allocation Well insofar as it is attributable to a Spacing Unit that includes Royalty Lands. For this purpose, a well traversing a road allowance is treated as half within the Royalty Lands. (For context, Alberta does not consider road allowances in its Production Allocation Unit Agreements, so any PAUA outcome could be slightly different.)

A Horizontal Well will sometimes be inadvertently steered out of the target formation during drilling, particularly in thin formations. If this occurs towards the Toe of the well and that portion of the well is being Abandoned, the qualification in the definition of Toe addresses the issue. Insofar as this otherwise occurs, the Clause does not include any further adjustment mechanism because of the belief that it would typically be relatively minor. The Parties would need to discuss the matter at the time if this were a significant issue in a particular well, with the Working Interest owners also needing to consider if additional discussions were required with the applicable regulatory authorities in the context of any applicable Production Allocation Unit Agreement.

Subclause 2.03B: This Subclause gives the Royalty Payor a high degree of flexibility in its activities with respect to the planning, execution and operation of a Royalty Allocation Well. The Royalty Payor is to provide prior notice to the Royalty Owner of the intention to drill a Royalty Allocation Well, and is to include a copy of the preliminary survey plan associated with that well.

Subclause 2.03C: i) This Subclause is structured so that the methodology in the Clause will apply to every Royalty Allocation Well drilled under the Agreement. The alternative approach of requiring a separate royalty allocation agreement for each Royalty Allocation Well would offer negotiating leverage to a Party at the time the applicable well is being planned. Creating a consistent, logical methodology for all Royalty Allocation Wells before the drilling cycle avoids partner issues as the well schedule advances.

There may be circumstances in which the methodology contemplated in this Subclause will not be appropriate. As a consequence, the Subclause was structured to enable the Parties to negotiate a different handling of the issue in their Head Agreement or through a different negotiated outcome at the time with respect to any particular Royalty Allocation Well. The Royalty Payor, for example, should confirm that the obligations under this Clause would not conflict with its obligations under another agreement.

In addition, there may be circumstances in which a Royalty Payor drilling on Sections 1 and 2, for example, would prefer to pool diverse interests in Section 1 for tenure purposes and then use this Clause to address the relationship between Sections 1 and 2. Paragraph C(a) ensures that the allocation of production between Sections 1 and 2 is calculated using the Allocation Ratio and that production allocated to Section 1 is then further allocated in accordance with the terms of the pooling authorized by Clause 2.02.

ii) Using the simple example in annotation (i) of the definition of Allocation Ratio in which Alternate 1 applies, assume that the Royalty Payor drills a 2000m Royalty Allocation Well, that the Royalty Length is 600m and that there is oil production of 38 cubic metres/day (i.e., 239.1 b/d). The Allocation Ratio of 30% (600/2000) would see 11.4 cubic metres/day of oil allocated to the Royalty Lands (i.e., 342 cubic metres/30 day month). Assuming the typical 23.8365 divisor and the 5-15% sliding scale applied, the sliding scale ORR accruing to the Royalty Owner for that month would be 14.35% of the allocated 342 cubic metre volume.

iii) A Royalty Payor will sometimes place a Royalty Allocation Well on production prior to finalization and notification of the Allocation Ratio. Subject to any application of Alternate 2 of the definition of Royalty Allocation Ratio, Paragraph (c) allows it to calculate an initial Allocation Ratio by applying the Alternate 1 methodology to the preliminary survey plan used for the drilling of that well.

Subclause 2.03D: The definition of Allocation Ratio contemplates a potential modification to the Allocation Ratio if a Royalty Allocation Well is permanently plugged back and cemented off before production commences. Once placed on initial production, there is no further modification to the Allocation Ratio for a Royalty Allocation Well, unless the Parties agree to one.

Subclause 2.03E: A Royalty Allocation Well may have multiple Horizontal Legs. Subject to any application of Alternate 2 of the definition of Royalty Allocation Ratio, each is regarded as a separate Royalty Allocation Well for this Clause and Subclause 2.01A under the definition of Horizontal Well in Clause 1.02. However, the Royalty Payor is able to use an averaging methodology based on relative Total Horizontal Length to the sum of the Total Horizontal Lengths to determine the respective production volumes if it is not feasible to determine the production applicable to an individual Horizontal Leg.

Subclause 2.03F: i) Subject to any application of Alternate 2 of the definition of Royalty Allocation Ratio, the Royalty Payor will notify the Royalty Owner of the Allocation Ratio and the basis for its determination in reasonable detail within 45 days after the Royalty Payor receives the As Drilled Survey for the Royalty Allocation Well. The Royalty Owner has a window of 30 days within which to object to that determination. Insofar as the matter is not then resolved, it can be referred for resolution under Clause 8.01.

ii) This Subclause and the cash adjustment process in Subclause 2.03G will apply, *mutatis mutandis*, if a modification to the Allocation Ratio is required on the basis set forth in that definition.

Subclause 2.03G: Subject to any application of Alternate 2 of the definition of Royalty Allocation Ratio, this Subclause addresses the adjustment process if the final Allocation Ratio differs from the initial Allocation Ratio created from the preliminary drilling survey.

There will be many instances in which the adjustment process contemplated in this Subclause and Paragraph 2.03C(c) will not be relevant because of the diligence with which the Royalty Payor approaches its obligation to confirm the Allocation Ratio. There will be others, though, in which it does not have the same plotting technology or be as diligent in satisfaction of its obligations. While the adjustment process will have no application in the former circumstance, it offers real protection in the latter case.

Subclause 2.04A: i) Subclause A states that the Royalty Payor is the agent of the Royalty Owner for the handling and disposition of the ORR share of production insofar as the Royalty Owner is not taking the ORR in kind.

ii) In theory, Royalty Owners can best manage their share of production by taking the ORR in kind. A Royalty Owner's decision to take its ORR in kind will be a function of a number of factors. These include the economic significance of the product stream to the Royalty Owner, the location of the Royalty Wells in relation to its other operations, its ability to use facilities on better terms, the type of product and the Royalty Owner's relationship with the Royalty Payor. The likelihood that a Royalty Owner would take an ORR held under this document in kind is relatively low, as the typical ORR governed by this document will often be 5% or lower.

Subclause 2.04B: i) Subject to Subclause 2.04A, the Royalty Owner may take its share of the ORR in kind on a minimum of 60 days' notice to the Royalty Payor. This election is effective on the first day of the month next following expiry of that notice period. To illustrate, an election on April 15th becomes effective on July 1st. This election is exercisable separately for individual Petroleum Substances. It should only make this election if it is actually able to manage those volumes. (See Subclause 2.04F.)

ii) The corresponding 30 day election and revocation periods under Paragraphs 5.04A(b) and 5.04E(a) of the CAPL Farmout & Royalty Procedure are 60 days in this document to minimize the potential administrative burden on the Royalty Payor for what are typically expected to be relatively small ORRs in practice.

iii) The take in kind rights in the 1997 and 2015 documents are much more flexible than the provisions typically included in older industry agreements, even if the Royalty Payor is selling production under a contract. The traditional provision generally provided that the Royalty Payor was obligated to inform the Royalty Owner of the details of a proposed marketing arrangement, so that the Royalty Owner could elect if it wanted its share of ORR volumes sold under that contract.

That traditional obligation was not included in the document for three reasons. The first is that the Royalty Payor and Royalty Owner should probably have their respective marketing groups enter into a separate agreement for the ORR production if the volumes are significant. The second is the practical fact that the obligation would seldom be complied with, given the administrative burden, the proprietary nature of gas contracts and the small volumes typically involved. The third is that the low number of dedicated lands, reserves based contracts and the inclusion of the notice period would generally enable a Royalty Payor to replace a minor ORR volume taken in kind fairly easily by allocating other gas from its corporate pool or by purchasing gas in the market.

Subclause 2.04C: i) Subclause C addresses the transfer of possession to the Royalty Owner (or its nominee) at the First Point of Measurement if it takes in kind. The responsibility for Facility Fees outlined in this Clause can also apply if the "no deductions" Alternate of 2.01A(b)(2) were selected. This is because the Royalty Owner retains full responsibility for its share of Facility Fees if it chooses to take its gas and associated substances in kind under that Alternate. Costs incurred for those volumes up to the First Point of Measurement were for the account of the Royalty Payor under the 1997 document, but are handled on the same basis as is prescribed under Subclause 2.05A in the 2015 document. This enhanced flexibility could see the Royalty Owner assuming responsibility for its proportionate volumetric share of certain expenses incurred from the wellhead to and including the First Point of Measurement for the removal and handling of basic sediment, water and other associated impurities.

ii) The Royalty Payor is to provide production tankage capacity for an accumulation of ORR crude oil and liquids extracted at the wellhead consistent with the Royalty Payor's shipping schedule. In practice, the Royalty Owner would seldom require the 10-day capacity typically provided for in industry agreements that pre-dated (or did not use) the Overriding Royalty Procedure.

iii) Paragraph C(f) clarifies that the Royalty Owner does not assume any responsibility for lessor royalties applicable to production volumes it takes in kind from a Royalty Well. This Paragraph was introduced in the 2015 document to add clarity for users, but it reflects the traditional expectation for the handling of the issue in industry agreements. The premise in the Paragraph is that responsibility for those charges should not change because the Royalty Owner chooses to exercise its right to take in kind.

That being said, the first sentence of this Paragraph recognizes that Parties will sometimes structure their Agreement so that the Royalty Owner assumes full responsibility for the satisfaction of certain encumbrances out of its own share of the Overriding Royalty. The Parties would need to be very clear about any such obligation in their Head Agreement.

Subclause 2.04D: i) Subclause D largely equates a Royalty Owner to a non-taking owner under the 2015 CAPL Operating Procedure. This treatment is based on two principles. The first is that the Royalty Owner has an interest in the Petroleum Substances in place and as produced that places some responsibility on it to manage the ORR share of production. The second is that the Royalty Payor should not be obligated to extend the benefits of its own marketing and transportation efforts to royalty substances not taken in kind by the Royalty Owner.

This Subclause would generally have minimal impact for light gravity oil. There could be a material difference between the price actually obtained by the Royalty Payor under its corporate contracts and the Market Price for gas, though.

It may initially appear attractive to link the Royalty Owner's gas proceeds to those received by the Royalty Payor. There are several problems in trying to equate those prices, though. The first is that marketing arrangements are generally managed on the basis of the Royalty Payor's total corporate supply pool (rather than on the basis of dedicated contracts for particular lands), such that the Royalty Owner would face the risk that ORR production would often be allocated to contracts that were the least favourable for a particular period. The second is that the Royalty Payor has incurred risks to secure transportation capacity for which it is not being compensated. The third is that Royalty Payors are generally very reluctant to allow audit access to their marketing arrangements.

To attempt to introduce a greater element of certainty into the process, the definition of Market Price has been incorporated from the Operating Procedure under Clause 1.02. This offers greater flexibility than the corresponding provision in the 1997 document that linked the price for natural gas to the AECO-C one month index spot price. (See Clause 1.02 and the associated annotations, as well as the definition of Market Price and the related annotations in the Operating Procedure.)

ii) A marketing fee under Subclause 2.04F only applies insofar as a Royalty Owner that had elected to take in kind then fails to do so. This recognizes the additional effort of the Royalty Payor to manage the incremental volumes. There is no marketing fee under this document if the Royalty Owner does not elect to take in kind.

iii) If the Royalty Owner's normal practice is not to take its ORR in kind, it may wish to enter into a separate agreement with the Royalty Payor or to amend the Clause. In practice, both the Royalty Payor and the Royalty Owner would be motivated to negotiate a separate asset specific agreement for the sale of production not taken in kind if the ORR volumes were commercially significant.

One negotiated approach would have the Royalty Owner receive the same price as the Royalty Payor or a price linked to a recognized index price (as adjusted for transportation charges), possibly less a specified marketing fee analogous to that in Clause 6.04 of the Operating Procedure. This would probably require some extra restrictions on the Royalty Owner's right to take in kind.

Subclause 2.04E: i) Subclause E allows a Royalty Owner that has elected to take the ORR in kind to elect to re-establish the agency in Subclause 2.04A on a minimum of 60 days' notice to the Royalty Payor. This election would be effective as of the first day of the calendar month next following that 60-day period. (The CAPL Farmout & Royalty Procedure revocation period is 30 days.)

ii) Paragraph 2.04E(b) of the 2015 document allows the Royalty Payor to revoke an election to take in kind if a Royalty Owner that elected to take in kind failed to do so for more than 45 days.

Subclause 2.04F: Subclause F was introduced in the 2015 document. It allows the Royalty Payor to charge a marketing fee insofar as a Royalty Owner that elected to take in kind failed to do so. This marketing fee is double the marketing fee prescribed by Clause 6.04 of the Operating Procedure. This was done to reinforce to Royalty Owners that they should only elect to take in kind if they are serious about implementing that election and actually have the logistical ability to manage the ORR volumes. The Parties might consider modifying the document to include a higher fee because of the inconvenience factor associated with a Royalty Owner failing to take its production in kind after electing to do so, particularly if the ORR is a small one.

An even higher marketing fee (such as 5%) may be warranted in more remote operating areas because of the potential difficulty in managing incremental volumes when there may be limited ability to obtain required access to infrastructure.

Clause 2.05: i) Subclause A applies to costs through the First Point of Measurement in all cases. Subclauses B-E apply insofar as the Royalty Owner does not take the ORR in kind. The foundation of this Clause is that the Royalty Owner's interest is in the Petroleum Substances within, upon or under the Royalty Lands. The Royalty Owner also owns the Petroleum Substances as produced from a Royalty Well. Therefore, the Royalty Owner bears its share of expenses incurred beyond the First Point of Measurement to make the Petroleum Substances merchantable and to transport them to market, unless the "no deductions" Alternate 2.01A(b)(2) is selected for gas and associated substances.

There are two other reasons why the Royalty Owner is responsible for its share of those product enhancement costs. The first is that it is inconsistent to require the Royalty Owner to share in those expenses when it takes in kind, but not when it takes its share of cash proceeds. The second is that product enhancement costs, such as processing and transportation, add value to the product that is shared by the Royalty Owner. If the production were sold at the wellhead (or in an unprocessed state), the price received by the Royalty Payor (and the resultant proceeds received by the Royalty Owner) would be lower.

ii) A Royalty Payor that anticipates conducting secondary recovery on the Royalty Lands or otherwise on Royalty Lands in due course should consider carefully the degree to which this Clause offers it the level of deductions it requires. Input costs (water, steam, polymers, etc.), operating costs and production handling costs (sand, water, carbon disposal, etc.) associated with those activities will have a significant impact on project economics that could require special handling in the Agreement.

Subclause 2.05A: i) The document is much clearer about deductions against an ORR than was the case under older agreements. Resman Holdings Ltd. v. Huntex Limited (C. Warren Hunt Exploration Ltd.) and Berisoff and Hunt, [1984] 1 W.W.R. 693 (Alta. Q.B.) addressed a very brief agreement that did not refer to deductions. The agreement provided that the ORR payable on natural gas thereunder was "payable at the outlet valve to the pipeline, produced, saved and sold from the said lands". The Court determined that this meant that the ORR was calculated on the wellhead value after deduction of the applicable downstream costs for gathering, processing, etc. that were incurred to increase the value of the product. Amerada Minerals Corp of Canada v. Mesa Petroleum (N.A.) Co., [1987] 1 W.W.R. 107 (Alta. C.A.), affirming [1985] 4 W.W.R. 607 (Alta. Q.B.), addressed a provision in which the applicable production was "to be computed at the plant outlet free and clear of all processing charges". Issues arose with respect to: (a) complex gas processing facilities beyond the contemplation of the parties for which advances in technology had allowed NGL extraction functionality to be added over time to enhance returns; and (b) the use of fuel gas at the plant. The Court found that the expenses incurred to make the production marketable were not deductible, while those incurred to enhance its value were deductible. The Court also found that the ORR did not accrue with respect to the fuel gas used at the plant, as it was not marketed.

Another case of relevance is Acanthus Resources Ltd. v. Cunningham, [1998] 5 W.W.R. 646 (Alta. Q.B.), which related to deductions under a freehold lease for oil production. The royalty was based on "the current market value at the wellhead", and the Court found that this reference permitted deductions for costs incurred after the wellhead for such items as water removal and other treating costs (rather than just transportation costs). In essence, the wellhead value was calculated by deducting downstream costs.

ii) Note the treatment in Alternate 2.05A(1) of the costs to remove basic sediment, water and other impurities up to the First Point of Measurement. This reflects the traditional treatment in farmout agreements (including the 1997 document). Those costs are usually minor, and there could be a significant administrative burden to change a well-established industry practice for these cases.

As contemplated by the annotations to the 1997 document, the initial cost to remove sediment, water and other impurities through the First Point of Measurement can be significant. Parties sometimes negotiated modifications to that document in those cases.

Alternate 2.05A(2) was introduced in the 2015 document for those cases, so that the Royalty Owner can be responsible for its share of those costs from the wellhead, subject to the qualification in Paragraph A(2)(c) relating to the handling of water associated with fracing programs. Not charging the Royalty Owner for its share of those costs in those cases provides the Royalty Owner with a large benefit when the Royalty Owner owns the associated production.

The Alternate selected by the Parties under this Subclause also impacts the responsibility for costs through the First Point of Measurement under Paragraph 2.04C(d) if the Royalty Owner takes its ORR volumes in kind at the First Point of Measurement.

iii) Paragraph 2.05A(2)(c) has been included to differentiate the handling between water associated with a fracing program and water produced during normal producing operations. Even if this Alternate is chosen, this Paragraph ensures that the Royalty Owner is not responsible for any water handling costs relating to a fracing program before, during and immediately after that program, as those costs are more properly categorized as Completion costs, not production handling costs. The water associated with a fracing program will typically be substantially recovered during a "cleanup" period in which specialized equipment will be on site to manage the higher than normal water volumes. This Paragraph has its greatest impact for shale projects.

iv) Other than as provided in Paragraph 2.05A(2)(c), Alternate 2.05A(2) provides a similar outcome to the handling prescribed for all circumstances by Paragraph 4.01(a) of the CAPL Royalty Procedure, Version 1 (early 1990s).

v) It is possible (but unlikely) that Parties selecting the "no deductions" approach in Alternate 2.01A(b)(2) would agree to a sharing of water handling costs up to the First Point of Measurement on the basis contemplated in Alternate 2.05A(2). This would require some customization of their Agreement to deliver those outcomes, as the document presumes that this will not occur.

Subclause 2.05B: This Subclause applies to the costs of handling ORR production volumes after the First Point of Measurement.

Paragraph 2.05B(b): Paragraph 2.05B(b) is different from traditional industry agreements, in that Facility Fees are also applied against crude oil and liquids extracted at the wellhead. This recognizes the fact that the Royalty Payor's facilities may be required to prepare these substances for market, as is often the case with medium or heavy crude. The application of the Facilities Fees definition also provides protection against the expenses potentially associated with a non-arm's length use of facilities for crude oil.

Subparagraph (iii) has been included because of some of the more complex product handling arrangements respecting shale activities, such as the use of "stabilizers" and a potential requirement for secondary removal of water.

Subclause 2.05B does not apply to gas and associated substances if the "no deductions" Alternate 2.01A(b)(2) is selected, though. There would be no applicable deductions for Facility Fees under Subclause 2.05B.

Subclause 2.05C: i) The foundation of the Clause is the general principle that a Royalty Owner not taking in kind should bear its volumetric share of product enhancement costs incurred after the First Point of Measurement. However, the potential deductions often associated with gas and the use of the Royalty Payor's owned facilities can be high, so this Subclause is introduced to qualify the degree to which the blanket authority to take deductions under Subclause A (if Alternate 2.05A(2) applies) and B is qualified.

It has been common since the mid-1980s for Royalty Owners to include controls to manage those deductions. Subclause C includes three Alternates that can be used singularly or in combination. Users must understand three things about them. Firstly, the Alternates limit the availability to take actual deductions otherwise permitted under Alternate 2.05A(2) and Subclause B-no Alternate allows the Royalty Payor to take deductions for costs that actually were not incurred. Secondly, the selection of "none of 1, 2 or 3" does not mean that no deductions are permitted-instead it means that there are no limits on the deductions permitted under Subclause B. Thirdly, the interrelationship of the selected Alternates is that the lowest authorized deduction applies if more than one Alternate is chosen-the same outcome that applied under the 1997 document.

ii) Alternate 1 has been traditionally used. However, it posed problems for gas in Alberta between January, 1994 and 2009 because of the Alberta Royalty Simplification Program. That program had seen allowable costs allocated to each owner's capital pool, making them difficult to track at a facility level. The 2009 Alberta changes see costs aligned at an AER facility level.

The negotiated cap on deductions in Alternate 2 and the "no deductions" Alternate 2.01A(b)(2) have been widely used by Royalty Owners to manage the ORR revenue stream on gas and associated substances. This is particularly the case if the Royalty Payor is anticipated to use facilities owned by it. Users must recall that the cap on deductions applies after the Market Price has been adjusted to reflect transportation tolls after the plant and enrichment costs contemplated under Subclause 2.05D.

The cap on deductions approach in Alternate 2 began to be used widely in industry in the late 1980s. The "no deductions" approach in Alternate 2.01A(b)(2) began to be used by a subset of industry in the mid-1990s.

Alternate 3 was introduced in the 2015 document. It reflects the fact that periods of favourable gas pricing have seen the percentage cap of Facility Fees to Market Price offer a greater than expected latitude in charging Facility Fees for owned facilities against ORR revenues, including a higher recognized gas cost allowance. Alternate 3 includes an absolute financial cap for those deductions, notwithstanding that the proposed deductions may still be within the range of the cap permitted under Alternate 2.

To illustrate the impact of Alternates 1, 2 and 3 if all were selected, assume that: (a) the heating value of the applicable gas is 1000BTU/cf; (b) the Market Price for applicable gas volumes were \$5.00/gigajoule (\$6.00 sales price, less transportation expenses of \$1.00 after the outlet of the gas plant); (c) the Alternate 1 calculation would allow deductions of \$100.00/10^3m^3 (\$2.68/gigajoule); (d) the cap on deductions in Alternate 2 were the typical 50%; and (e) the financial cap on deductions in Alternate (3) were \$80.00/10^3m^3 (\$2.14/gigajoule). Alternates 1 and 2 would respectively allow \$100.00/10^3m^3 and \$93.14/10^3m^3 in deductions (\$2.68 and \$2.50/gigajoule), but the inclusion of Alternate 3 would limit deductions to \$80.00/10^3m^3 (\$2.14/gigajoule). (Gigajoules, rather than mcf, are used to describe this concept because gas sales and index pricing are presented in the context of heating value, rather than the mcf reference that is used to describe production volumes. The conversion factor is that 1 10^3m^3 is equal to 37.257 gigajoules. For context, one gigajoule is also approximately 0.948mcf, with one mcf being approximately 1.055 gigajoules.)

iii) As noted in the previous annotation, transportation expenses after the outlet of the applicable gas plant are handled as an adjustment to the Market Price, rather than as a deduction. The Market Price in that example was always adjusted for \$1.00 of transportation expenses before the application of the selected Alternate(s) to the adjusted Market Price.

iv) Parties have often structured Alternate 2 so that the "deductions must not be greater than 50% of the Market Price". Increasing the percentage to 60% benefits the Royalty Payor. Lowering it to 40% benefits the Royalty Owner. The traditional 50% cap may be excessive in a high price environment unless high handling expenses are expected (e.g., sour gas using third party facilities). Royalty Payors will probably struggle with a low cap if they will be using a third party facility that has high fees.

v) It is easy to perceive this Subclause as benefiting only the Royalty Owner because of the controls it introduces on deductions. A Royalty Payor that owns the facilities that are anticipated to be used to handle production volumes from an attractive prospect can use it to its advantage, though. This is because it can use the options in the Subclause to differentiate itself from its competition by offering controls on deductions against the ORR that are very attractive to a potential Royalty Owner.

vi) The selection of an Alternate in Subclause C can still be relevant if the "no deductions" gas Alternate in 2.01A(b)(2) is selected. There are potentially high deductions associated with some oil projects.

vii) The document does not include a fourth option of allowing no deductions from the wellhead to the ultimate point of sale. A Royalty Owner's greatest concern about deductions will typically be those for use of the Royalty Payor's own gathering, transportation and processing infrastructure. In this regard, the "no deductions" optionality offered by Alternate 2.01A(b)(2) actually delivers the same result through the outlet of a gas plant, while also handling any enrichment expenses appropriately. Transportation expenses after the gas plant are handled as an adjustment to the Market Price under that definition, such that further customization to that definition would be required by Parties wanting to achieve an all-encompassing "no deductions" outcome. (See also annotation 2.01(ix).)

Parties considering this type of customization would also want to consider very carefully the handling of any enrichment expenses in their customized provision for the reasons noted in the annotations on Subclause 2.05D.

viii) Users also need to realize that the deduction regimes applicable to Title Documents that are freehold leases and this Agreement will probably be inconsistent. The Royalty Payor will be responsible for compliance with its contractual obligations under both this Agreement and its freehold leases, such that there is no ability to apply a "one size fits all" approach to deductions.

Subclause 2.05D: Production sometimes must be enriched with other hydrocarbon products to make the product suitable for transportation or to make the product marketable. This is particularly the case for heavy oil and bitumen. This Subclause has been structured to ensure that the Royalty Payor is kept whole when it is required to incur this type of cost. Agreements are typically silent on this issue.

The structure of this Clause and the handling of deductions (and the associated controls on deductions) are designed to ensure that the value of the ORR stream is normalized to the real value of the produced resource before making the Subclause 2.05C calculations. This sees the Royalty Payor net out enrichment expenses incurred by it to facilitate marketing of production volumes.

Any other outcome would see the Royalty Owner receiving the benefit of the enrichment expenses by being paid its ORR on the higher value product without incurring any responsibility for the associated enrichment of the product stream by the Royalty Payor.

Subclause 2.05E: This Subclause states that the deductions in the Clause have been presented as cash deductions for simplicity. As an interest in land, the Royalty Owner's rights and obligations would ideally be expressed in production volumes, not by referring to the proceeds of sale and cash deductions from those proceeds. This Subclause reinforces that Clause 2.05 does not intend in any way to detract from the ORR as an interest in land.

Subclause 2.06B: i) As was the case in the 1997 document, the Royalty Payor is to forward sale proceeds to the Royalty Owner by the 25th of the month following receipt of the proceeds, to reflect the logistics of the production accounting cycle. As the Royalty Payor usually receives its sale proceeds on about the 25th of the month following the production month, the typical pre-Overriding Royalty Procedure requirement to pay the Royalty Owner by the end of that month was seldom satisfied. In practice, the payment is delayed a further month if the Royalty Payor does not receive its production revenue in the month following production.

ii) To what degree should the Royalty Owner bear the risk if the purchaser selected by the Royalty Payor fails to pay for the production? On the one hand, the Royalty Owner is a passive owner that chose to delegate that decision to the Royalty Payor. On the other hand, the Royalty Payor chose to sell a portion of its undedicated corporate supply to that purchaser. Relieving a Royalty Payor entirely from responsibility in this case would encourage Royalty Payors to allocate ORR production to problem purchasers if problems arose. As this would be an unacceptable result, the provision was structured to protect the Royalty Owner on this issue.

The 2015 document was modified to address the handling of this issue in a manner that is more consistent with the handling in Subclause 6.06A of the Operating Procedure. This outcome is more favourable to the Royalty Payor than was the case in the 1997 document. The Royalty Payor will be fully responsible for payment, unless it can reasonably demonstrate that both the ORR volumes and the Royalty Payor's share of volumes were being sold specifically under that contract <u>and</u> the Royalty Payor has made reasonable efforts to collect the applicable amount from that purchaser. However, there is a duty on the Royalty Payor to allocate any such recovered amount from that purchaser firstly to the Royalty Owner.

A Royalty Payor that is uncomfortable with this outcome should modify the provision or, in the alternative, obtain the Royalty Owner's consent to a disposition under the contract, so that there is a direct linkage of ORR volumes and sales arrangements.

Clause 2.07: i) The Royalty Owner's default remedies are in Clause 7.01. Clause 2.07 is similar to the Operator's lien provision of the CAPL Operating Procedure. (See, for example, Subclause 5.05A of the CAPL Operating Procedure.) It may be more difficult to apply in practice, though, particularly if the Operator also purports to exercise its rights with respect to the Operator's lien.

ii) See annotation (ii) respecting Article 2.00 for an overview of the interest in land question.

Clause 2.08: i) It is common for a Royalty Payor to operate producing wells on other lands in the same pool as Royalty Wells. The Royalty Payor may be tempted to discriminate against production from the Royalty Wells because of the lower netbacks resulting from the ORR. Given the Royalty Owner's lack of control over field operations, this Clause has been included to provide some protection for it. Ultimately, the Royalty Owner's best defence against potential abuse in this situation is to monitor production against productive capability for any Royalty Well of economic significance. This is unlikely to be an issue for wells included in units.

Greater protection was offered for a Royalty Owner in the 2015 document because of the ability to refer a dispute about performance of the obligations under this Clause to the dispute resolution mechanism in Clause 8.01. The potential reference of the issue to arbitration encourages the Royalty Payor to discuss the dispute with greater diligence than may otherwise be the case.

ii) Some companies include a provision stating that the Royalty Payor does not have any obligation to develop because of some American cases that found an implied covenant to develop. That type of provision has not been included. There is no comparable Canadian case law. Such a provision might also arguably enable a Royalty Payor to allow Royalty Lands to expire with the intention of promptly reacquiring those rights free of the ORR.

iii) Some Royalty Owners attempt to address the subsequent development of Royalty Lands by including a reversionary provision in the Head Agreement whereby undeveloped Royalty Lands revert by a specified date or at some other specified event.

iv) Some Royalty Owners attempt to address this by including a density drilling requirement. This requires the Royalty Payor to use reasonable efforts to have the same drilling density as for laterally or diagonally adjacent Spacing Units for a productive formation included in the Royalty Lands. A Royalty Owner might consider this if the Royalty Payor is known to have the offsetting rights.

Clause 2.09: i) Unlike the CAPL Farmout & Royalty Procedure, this is an optional Clause in this document. The Royalty Payor has a contingent surrender obligation to the Royalty Owner. The Royalty Payor's primary obligation is to comply with its surrender obligation to all Working Interest partners under the Operating Procedure or its governing agreement, as applicable. (See also the annotations on Clause 1.04.) This Clause applies insofar as Royalty Lands are still proposed for surrender after that process or there is only one Royalty Payor. Article 11.00 of the 2015 CAPL Operating Procedure will apply, *mutatis mutandis*, except that the notice and response periods have been reduced to 20 and 10 days respectively.

ii) <u>Masia Minerals Ltd.</u> v. <u>Heritage Resources Ltd.</u>, [1981] 2 W.W.R. 140 (Sask. C.A.), affirming [1979] 2 W.W.R. 352 (Sask. Q.B.), addressed a situation in which a payor of an ORR surrendered lands subject to the ORR without complying with its surrender obligation to the holder of the ORR. Following the reacquisition of the lease by the party responsible for the ORR, the ORR holder sought ownership of the lease. The Court held that the ORR holder would have been free to pursue an action for damages after the lease was first lost. However, once the lands were reacquired and the party originally responsible for the ORR confirmed that the ORR applied to them, the ORR holder was in the same position as it had originally had been before the surrender.

iii) A Royalty Owner that is not aware that Title Documents had been surrendered could face limitations issues in pursuing a claim. See, for example, <u>Western Oil Consultants</u> v. <u>Great Northern Oils Ltd.</u> (1981), 121 D.L.R. (3d) 724 (Alta. Q.B.).

Clause 2.10: i) The audit rights in this Clause apply to the Overriding Royalty.

ii) Audits are to be conducted on the same basis as in the standard form 2011 PASC Accounting Procedure and, insofar as they do not conflict with that document, the recommended handling in the then current PASC Joint Venture Audit Protocol Bulletin. From a timing standpoint, this means that the auditor would submit exceptions within two months after completing the field work and that the Royalty Payor would respond to exceptions within six months after receipt. There would then be an ongoing rebuttal/clarification process that would allow the audit to be closed and a final report to be written within one year after the date the exceptions were submitted. Although the 2011 PASC was not widely accepted at the time the 2015 document was completed, the provisions of that document that apply under this Clause are not regarded as contentious.

iii) Audits are to be conducted at the sole cost and expense of the Royalty Owner(s).

iv) Subclause 2.10B is based on Subclause 106(F) and Clause 107 of the 2011 PASC Accounting Procedure. Statements are generally deemed to be true and correct after a specified date. The one exception is if an error discovered in the current period reasonably appears to have extended to a prior period (e.g., using an incorrect % or applying an erroneous tract factor), as it is not reasonable for either the Royalty Owner or Royalty Payor to profit from the error. Any such adjustment will be handled on the basis prescribed by the PASC adjustment provision, unless the Parties otherwise agree.

v) Any dispute about a proposed retroactive adjustment outside the 26-month audit period is to be resolved under Clause 8.01.

vi) Certain disputes about a proposed retroactive adjustment are to be resolved under Clause 8.01. A Royalty Owner could face limitations issues in pursuing or resolving all or a portion of a claim, though, if the Royalty Owner "knew or ought to have known" about the claim prior to the applicable time set forth in Clause 1.07 of the Operating Procedure (incorporated by reference under Clause 1.02). See, for example, 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.), and Meek (Trustee of) v. San Juan Resources Inc., 2005 ABCA 448 (Alta. C.A.). Those cases recognized that "ought to have known" calls for "reasonable diligence" on the part of the Royalty Owner, and that what constitutes "reasonable diligence" depends on the facts of each case. This determination can be coloured by whether the Royalty Owner is involved in the oil and gas industry. If the Royalty Owner is involved in the oil and gas industry, there may be an obligation on it to make reasonable inquiries about its royalty rights (Jensen). If, on the other hand, the Royalty Owner is not involved in the oil and gas industry, it may be that, absent clear information to the contrary, it is entitled to assume that the Royalty Payor will honour all of its royalty payment obligations (Meek). The Court in Jensen also held that a separate limitation period arises with respect to each missed periodic payment. In the absence of agreement, it is also important to remember that the limitations clock is still ticking during the period in which negotiations continue prior to initiation of a legal action.

Subclause 3.01A: i) The 1997 version of this document did not provide the Royalty Owner with any right to well information from Royalty Wells. This reflected two major assumptions-that the ORR percentage would typically be relatively modest and that a Royalty Owner with a non-convertible ORR probably had a passive interest in the Royalty Lands. Although those assumptions will be valid for many Agreements, they are not always valid. As a consequence, users often amended their Agreements to provide the Royalty Owner with access to well information from Royalty Wells on the same basis as is required for Earning Wells under the CAPL Farmout & Royalty Procedure.

This Article was amended as of the 2015 document to provide optionality for users on this point through the inclusion of optional Paragraph 3.01A(b) and the supporting provisions in the remainder of Article 3.00.

ii) As had been the case for the CAPL Farmout & Royalty Procedure, no model well information requirement Schedule was created in conjunction with the Overriding Royalty Procedure. The Royalty Owner's well information requirements are to be set forth on the Royalty Owner's own well information sheet, which will be included as a Schedule if optional Paragraph 3.01A(b) is selected to apply. This reflects the practical fact that the technical personnel who use that data work with well information sheets, rather than the applicable Agreement. There may be instances in which the Parties prefer to incorporate the well information requirements from Article 7.00 of the Operating Procedure by reference, though, particularly for higher cost, more complex operating areas.

iii) This Subclause was modified significantly in the 2015 CAPL Farmout & Royalty Procedure to recognize that the Royalty Payor may be unable to obtain any required consent to a release of the information from applicable third party owners under an agreement in existence at the time that the ORR was created, after making reasonable efforts to obtain that consent.

The qualification with respect to the confidentiality requirements under an existing agreement is designed to prevent the circumstance in which the Royalty Payor would find itself in breach of contract under either the existing agreement or this Agreement if there were third parties to the existing agreement that were not a Party to this Agreement.

That qualification only applies to other agreements that are existing agreements. It does not extend to any new agreement that the Royalty Payor negotiates. The onus is on the Royalty Payor to ensure that any such subsequent agreement is negotiated in a way that satisfies any obligation to the Royalty Owner under this Clause. Royalty Payors that are uncomfortable with this handling of new agreements should consider modifying the Clause.

iv) Paragraph 3.01A(a) is primarily intended to alert the Royalty Owner when a Royalty Well is being drilled. The onus is on the Royalty Owner to make a custom modification if it requires some other general information not captured under Paragraph 3.01A(b).

v) As noted above, Paragraph 3.01A(b) was introduced as of the 2015 document to offer greater optionality for Royalty Owners that routinely modified the 1997 versions of the CAPL Farmout & Royalty Procedure and CAPL Overriding Royalty Procedure to provide them with well information from all Royalty Wells, subject to any application of the Crown sale deferral in Subclause 3.01B.

Subclause 3.01B: i) This Subclause applies if Paragraph 3.01A(b) has been selected. It addresses a potential deferral of the delivery of well information for an additional Royalty Well if parcels meeting certain criteria have been offered at a Crown sale, and mirrors the handling on this issue in the CAPL Farmout & Royalty Procedure.

The Royalty Payor may delay providing that information if the applicable Royalty Well is being drilled to evaluate formations of the Royalty Lands that correspond to those that have been offered at a Crown sale within 3.2 km of the Royalty Well location.

ii) The stratigraphic linkage of the Crown sale parcel to the Royalty Well is handled more clearly in the 2015 documents than in the 1997 CAPL Farmout & Royalty Procedure.

iii) A Royalty Payor that anticipates a freehold leasing program in conjunction with its drilling program may wish to consider modifying this Subclause to provide it with a different data release process for Royalty Wells to which this Clause applies.

Clause 3.02: i) This Clause is only relevant if Paragraph 3.01A(b) has been selected to apply.

ii) Royalty Payors drilling through shallower rights not included in the Royalty Lands sometimes attempt to exclude data from those rights. This is based on their interpretation that their duty to provide information under the 1997 CAPL Farmout & Royalty Procedure type Clause is limited to only those formations included in the Royalty Lands.

The 1997 document did not support that interpretation. There is no language in the Article of that document that limited the duty to provide information to a portion of a well linked to the formations included in the Royalty Lands. It would have been very easy to have included that qualification in the 1997 document if that had ever been the intention.

The 1997 structure reflects two practical considerations. Firstly, the costs incurred to drill through those formations and to conduct the logging program required under the Regulations were taken into account by the Parties when they structured their transaction. The second is that regulatory authorities typically require logs to be run in the entire wellbore, not just that portion pertaining to the Royalty Lands.

Notwithstanding that perspective, the existing ownership split between intervals may sometimes see the Parties negotiate a limitation of access to this data at the time of the original negotiation.

It is clear as of the 2015 documents that the Royalty Owner: (a) is entitled to drilling information (including logs) for all formations not deeper than 15m below the penetrated Royalty Lands at that location; and (b) is only entitled to preliminary formation specific evaluations (e.g., cores, drillstem test), Completion and production information from formations included in the Royalty Lands. This recognizes that there may be situations in which the Royalty Payor is drilling a well in part to evaluate its own regional exploration ideas or P&NG rights it already holds.

Subclause 4.01A: Note the distinct treatment between liability and indemnity. The Royalty Owner faces the legal risk that the provision could be held to be solely an obligation to indemnify if the distinction between the two is blurred. That could limit the Royalty Owner's ability to receive the expected protection for direct damage to the Royalty Owner's own property. This is a greater risk under older forms of farmout agreements that pre-date the CAPL document or for which parties chose not to use the applicable CAPL document. (See Mobil Oil Canada, Ltd. v. Beta Well Service Ltd. (1974), 43 D.L.R. (3rd) 745 (Alta. S.C., App. Div). More 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.).)

Subclause 4.01B: i) The last sentence clarifies the activities for which the Royalty Payor may rely on the Royalty Owner's written authorization in order to avoid sole responsibility for Losses and Liabilities. The ability to use the Royalty Owner's written instructions or approval as a shield should only exist if the applicable act, omission or failure to act was inherent in the instructions or approval. Prudent instructions implemented in a reckless manner should not allow the Royalty Payor to avoid responsibility for its performance. The addition of the last phrase in this document is consistent with the qualification in the definition of "Gross Negligence or Wilful Misconduct" introduced in the 2007 CAPL Operating Procedure.

ii) The Royalty Owner would still be required to prove its damages in all cases.

iii) There is no overall exclusion of responsibility for "Extraordinary Damages", as is found in Clause 4.04 of the 2015 CAPL Operating Procedure. Instead, Subclause 4.01B requires that the Royalty Owner's Losses and Liabilities be a "direct result" of the applicable Royalty Payor act, omission or failure to act.

There were two reasons that type of provision was not included.

The first is the major difference in the Royalty Owner-Royalty Payor relationship relative to the relationship between the Operator and Non-0perators under the Operating Procedure. The basic premise under the Operating Procedure is that losses from Joint Account activities will be for the Joint Account in the absence of special circumstances.

The second is the legal protection already afforded to a Royalty Payor under the general law of damages. This includes limits, such as a "remoteness" test, on the range of damages that a Court could award for any Losses and Liabilities resulting from the Royalty Payor's activities. The net effect is that there are significant constraints on a Court's ability to make an award for "indirect" type damages.

Clause 4.02: The principal Operations conducted by the Royalty Owner hereunder would be Operations in Reserved Formations.

Clause 5.01: i) Given industry's familiarity with the CAPL Assignment Procedure, there is no need to include it as a Schedule. The then current version of the CAPL Assignment Procedure is incorporated by reference.

It applies to all dispositions made under Article 5.00. It does not apply to other dispositions between the Parties by operation of the Overriding Royalty Procedure (i.e., surrender). Recognition for any such disposition is inherent in the operation of the applicable provision hereunder. Issuance of a notice of assignment for a mandated disposition would delay recognition and introduce unnecessary administrative effort and possible confusion that would typically exceed the benefits of additional documentation.

ii) The outcomes in this Clause mirror the handling in Subclause 24.04A of the 2015 CAPL Operating Procedure. The annotations in that Clause offer additional insights on the use of the CAPL Assignment Procedure.

iii) Clause 24.03 of the 2015 CAPL Operating Procedure has been incorporated by reference in Clause 1.02. This was done primarily to protect the Royalty Payor if a Royalty Owner Party proposes a disposition of its ORR to multiple assignees.

iv) Subclause 24.04B of the 2015 CAPL Operating Procedure will apply, *mutatis mutandis*, to the handling of any associated notice of assignment. This enhances the level of certainty in the manner in which third parties are identified if there are segregated interests, and is consistent with the CAPLA "Segregation Protocol".

Clause 5.02: The consent not to be unreasonably withheld mechanism will apply to dispositions of interests in the Royalty Lands by either the Royalty Payor or the Royalty Owner.

Clause 6.01: i) A Royalty Owner Party will often retain responsibility for administration of the Title Documents. The "Title Administrator" concept was introduced in the 2007 CAPL Operating Procedure to address this issue more directly because of the likelihood that the Operator's obligations may not extend to the maintenance of all Title Documents. The inclusion of this Clause should cause Parties to consider this issue more carefully, and to address their expectations explicitly in the Head Agreement.

A Royalty Owner Party that has the land administration responsibility has corresponding rights and duties. (See also the annotations on Clause 3.10 of the 2015 CAPL Operating Procedure.)

This could be addressed relatively simply in the Head Agreement with a Clause such as the following: *"Notwithstanding anything else in this Agreement, <X> will be the Title Administrator of the Title Documents in accordance with Clause 6.01 of the Overriding Royalty Procedure."*

ii) There could be several different Title Administrators in some circumstances. The Parties would need to link the responsibility to the applicable Title Documents.

iii) Notwithstanding the retention of certain reserved lands, the nature of a contemplated development is such that the Parties might consider a provision whereby the Royalty Payor assumes responsibility for administration of the Title Documents once a critical mass of development wells are drilled under the Agreement (e.g., more than Z wells in the Y formation).

Assume, for example, that the Royalty Payor only held rights below the base of the X formation, the Royalty Owner's retained shallow rights have minimal production/limited potential and the Royalty Payor is operating a capital intensive shale development in the Y formation. It may be preferable in that circumstance to have the Royalty Payor's interest recognized under the applicable Title Documents and to have the Royalty Payor assume responsibility for administration of the Title Documents. (This would require the Royalty Payor to hold the Royalty Owner's interest in trust for the formations in which the Royalty Payor did not acquire any Working Interest under the Agreement.)

Clause 6.02: This Clause only applies insofar as Clause 6.01 sees a Royalty Owner Party acting as the Title Administrator for any of the Title Documents. It allocates land maintenance charges on the basis of the Working Interests in the Royalty Lands without regard to Reserved Formations (i.e., the Royalty Owner would not have any responsibility for rentals for any Reserved Formations). The Parties should clarify the responsibility for land maintenance charges in the Head Agreement if the approach in this Subclause is not acceptable. Any compensatory royalties, however, remain the responsibility of the working interest owner(s) in the applicable formation(s).

Clause 7.01: The incorporation of the default provisions of the Operating Procedure in Clause 7.01 provides the Royalty Owner with greater protection against financial defaults than was typically provided under agreements that did not use the Overriding Royalty Procedure. Those provisions link to the Royalty Owner's lien created under Clause 2.07. At the same time, those provisions provide the Royalty Payor with the same protection granted to the defaulting party under the Operating Procedure. This Clause is much simpler than the default provisions in the CAPL Farmout & Royalty Procedure, given the likelihood that defaults hereunder would be financial.

Clause 8.01: i) This provision reflects the increased use of appropriate dispute resolution approaches to resolve disputes. It requires the Parties to select if they will apply the Dispute Resolution Article of the 2015 CAPL Operating Procedure on a *mutatis mutandis* basis. (See that Article and the associated annotations for additional insights.)

Arbitration under that Article for the specified list of disputes sees the application of the *Arbitration Act* (Alberta), as supplemented by prescribed "rules" that flesh out the manner in which an arbitration is conducted. If the Operating Procedure Article is not selected to apply, arbitration will still be used for the listed disputes. However, any arbitration for those specified dispute types would be under the *Arbitration Act* (Alberta) without being supplemented by any prescribed rules. Normal legal remedies would ultimately otherwise apply to all other disputes for which adjudication is required.

ii) 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 negotiations 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, without any apparent issues, on ROFR values (since the 1971 version), title preserving well issues (since the 1990 version) and a range of "Production Facility" issues (since the 1990 version).

iii) The specific disputes that would ultimately be referred to arbitration under this Clause are typically fact-based items for which an expedited response (with minimal damage on the longer-term relationship) is desired. The specific dispute types that would be referred to arbitration for resolution are:

(a) a determination under Subparagraph (b)(ii) or (iii) of the Clause 1.02 definition of Facility Fees;

(b) the determination of an Allocation Ratio with respect to a Royalty Allocation Well under Paragraph 2.03F(b);

(c) if the Royalty Payor has used reasonable efforts to produce a Royalty Well equitably relative to certain offsetting wells (Clause 2.08); or

(d) Subclause 2.10B (a proposed audit adjustment applying retroactively beyond the normal 26-month audit period to the extent contemplated in the applicable PASC Accounting Procedure provision incorporated by reference therein) if the amount in dispute is less than the financial limit prescribed in Paragraph 8.01(d);

The Parties remain free to agree to refer any other dispute to arbitration instead of pursuing judicial proceedings.

Clause 9.01: i) Clause 9.01 applies to the Royalty Owner's operations and activities respecting the Reserved Formations. (See also the definition of Reserved Formations in Clause 1.01 and the related annotations.)

ii) The existence of Reserved Formations also potentially brings into play a potential application of the dual use well provision of the Operating Procedure (Clause 10.06) in due course. That Clause allows a Party to import a well into the Agreement in certain circumstances for Operations within solely the jointly held rights. Use of a well for two or more different ownership sets is always a matter of negotiation under that Clause.

Clause 9.02: This Clause was introduced in the 2015 document. It creates an obligation on the Royalty Payor similar to that in Clause 9.01 with respect to the impact of the Royalty Payor's Operations on the Reserved Formations.

ADDENDUM
I-CORRELATION TO FARMOUT & ROYALTY PROCEDURE

Provision	Overriding Royalty Procedure	Farmout & Royalty Procedure
Definitions & Interpretation	**1.00**	**1.00**
Definitions	1.01*	1.01
Incorporation Of Provisions From 2015 CAPL Operating Procedure	1.02*	1.02
Multiple Royalty Owner Parties	1.03	1.03
Multiple Royalty Payor Parties	1.04*	1.04
Modifications To CAPL Form	1.05	1.05
Overriding Royalty	**2.00**	**5.00**
Quantification Of Overriding Royalty	2.01*	5.01
Effect Of Pooling Or Unitization On Calculation	2.02	5.02
Royalty Allocation Methodology For Certain Hz Wells	2.03	5.03
Royalty Owner's Rights To Take ORR In Kind	2.04*	5.04
Royalty Payor's Allowed Deductions	2.05	5.05
Monthly Accounting To Royalty Owner	2.06	5.06
Royalty Owner's Lien	2.07	5.07
Royalty Wells To Be Produced Equitably	2.08	5.08
Royalty Owner's Rights Upon Surrender	2.09*	5.09
Audits Of Overriding Royalty	2.10	5.10
Other Miscellaneous Articles		
Well Information To Royalty Owner	3.00*	9.00
Liability And Indemnity	4.00	11.00
Assignment	5.00	12.00
Land Maintenance Costs	6.00*	18.04, 13.00
Default	7.00*	14.01B&F
Dispute Resolution	8.00	15.00
Reserved Formations	9.00	16.00

***** The handling of topics in the CAPL Overriding Royalty Procedure is inherently different than that in the CAPL Farmout & Royalty Procedure because there are no Earning Wells being drilled under the Overriding Royalty Procedure. The asterisked references indicate provisions in which there are special modifications in this document to reflect different considerations applicable to an ORR governed by this document. These include:

-Differences in language to accommodate the "reserved" and "granted" ORRs potentially governed by this document (i.e., definitions of Overriding Royalty, Royalty Lands and Royalty Owner; Clause 2.01, Clause 2.07 and related annotations);
-Differences in the CAPL Operating Procedure provisions incorporated by reference in Clause 1.02 (e.g., use of Spacing Unit, no insurance obligation, deletion of many operational type provisions, need to populate addresses for service);
-Clause 1.04-no requirement to obtain Royalty Owner consent to a change to the Royalty Payor representative;
-Clause 2.04-increase notice periods for take in kind elections and revocations from 30 days to 60 days to reduce the administrative burden associated with what will typically be small ORRs;
-Clause 2.09-optional surrender provision;
-Article 3.00-option whereby Royalty Owner may obtain well information from Royalty Wells;
-Article 6.00-streamlined provisions respecting the possibility that a Royalty Owner could be the Title Administrator and the allocation of land maintenance charges to the Royalty Lands;
-Article 7.00-streamlined default provision that offers similar rights for financial defaults; and
-No provision offering rights upon Abandonment, such that this would need to be a custom modification negotiated by the Royalty Owner.

II-OVERRIDING ROYALTY PROCEDURE ELECTIONS AND AMENDMENTS

1. **Effective Date (Clause 1.01)**: ________________

2. **Incorporation Of Provisions From 2015 CAPL Operating Procedure (Clause 1.02):**
   (a) Definition of Market Price: Optional sentence will ____/will not _____ apply.
   (b) Clause 18.01 (Confidentiality Requirement): Optional sentence will ____/will not ____ apply.

3. **Quantification Of Overriding Royalty (Subclause 2.01A, if applicable):**
   (a) For crude oil, Alternate ___ will apply (Specify 1 or 2).
   - If Alternate 1 applies: ____%.
   - If Alternate 2 applies, divided by _______ and not less than ____% or more than ____%.

   (b) For all other Petroleum Substances, Alternate ___ will apply (Specify 1 or 2).
   - If Alternate 1 applies: ____ %
   - If Alternate 2 applies: (i) _____%; and (ii) ____%.

4. **Definition Of Allocation Ratio (Subclause 2.03A):** Alternate ___ will apply (Specify 1 or 2).

5. **Royalty Payor's Allowed Deductions (Clause 2.05), if applicable**:
   (a) Costs through First Point of Measurement (Subclause 2.05A): Alternate ___ will apply (Specify 1 or 2).
   (b) Limitations On Deductions (Subclause 2.05C): Alternate(s) (Specify): (i) 1 only _____; (ii) 2 only ______; (iii) 3 only______; (iv) 1, 2 and 3 _____; (v) other combination of more than one of 1, 2 and 3 (Specify) __________; or (vi) none of 1, 2 and 3 ______.
   - If Alternate 2 applies, deductions not greater than ____% of Market Price.
   - If Alternate 3 applies, deductions not greater than: $________/$10^3m^3$.

6. **Royalty Owner's Rights Upon Surrender (Clause 2.09)**: This optional Clause will ____/will not _____ apply.

7. **Well Information To Royalty Owner (Paragraph 3.01A(b)):** This optional Paragraph will __/will not ___ apply.

8. **Dispute Resolution (Clause 8.01):** Article 21.00 of the CAPL Operating Procedure will ___/will not ___ apply.