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Risk Allocation in Operating Agreements for Unconventional Resources

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Model contracts play a principal role in reducing transaction costs. They offer parties a series of rules, which allocates risk so that delays, disagreements, over-expenditures, and under-capitalizations can be managed (or avoided altogether). The best model contracts are highly responsive, quickly adapting to new realities. Accordingly, top drafters are pressed to doggedly re-evaluate whether or not their model rules are optimal in light of the ever-changing nature of law and technology.

Modern hydraulic fracturing is a disruptive technology that shifts the incentives within oil and gas joint venture projects. Drafters are adjusting their contracts to adapt. Experimentation with model rules is presently occurring in jurisdictions such as the United States, Canada and Australia, where unconventional resources abound.

This adaptation of model contracts (e.g. the third industry draft of the proposed updates to the 2007 CAPL Operating Procedure) has created a debate as to which model rules will be best for unconventional shale projects. As a contribution, this article first introduces how modern hydraulic fracturing has changed risk allocation in joint ventures, and then considers a couple of the central debates over what changes might need to be made so that model contracts can successfully adjust to this new reality.

What's In The Rocks

Wood MacKenzie defines the conventional asset life cycle as having four phases: exploration, appraisal, development, and production. In the exploration phase, the operator determines if hydrocarbons exist. In the appraisal phase, the operator determines if hydrocarbons exist in paying quantities. In the development phase, the operator devises and executes a plan to get the hydrocarbons out of the geological formation as efficiently as possible. In the production phase, the operator follows through with the plan, ensuring production until the reservoir is no longer commercially viable. An additional fifth phase is the decommissioning phase, in which the operator concludes operations and carries out reclamation initiatives.

The unconventional asset life cycle of the shale play differs in important ways. For such projects, Wood MacKenzie has devised four alternative phases: concept, pilot, ramp-up and exploit. In the concept phase, the operator devises a technical strategy to maximize the potential profitability of a shale play based mainly on the information on hand about its geological characteristics and anticipated economics. In this phase, a number of well designs will be devised for the acreage. In the pilot phase, the operator tests the hypothesis of the concept phase against the reality of the play's geology and rate of return. It does so by drilling a number of wells to test techniques for extracting hydrocarbons from the shale.

As the operator succeeds with in the pilot phase, a greater number of wells are drilled. As more wells are drilled, the commercial viability of the shale acreage becomes much clearer. If the results of the pilot phase indicate the project will be as viable as projected, the operator will dramatically expand operations. This expansion of operations is a key feature of the ramp-up phase.

The exploit phase is not the same as the production phase of conventional projects. The operator will drill many wells across the acreage. It will attempt to standardize production by re-using a limited selection of well designs, established during the concept and pilot phases. This standardization process increases efficiency and reduces transaction costs. At the same time, this standardization cannot be too rigid, since shale plays may have sharp decline curves, which demand reworking to sustain production. Put differently, well options must be responsive to changes in the subsurface characteristics of the play. Schlumberger calls this model the "flexible factory" model, because it takes a factory-style approach to standardization and combines it with a willingness to be responsive to change.

Ideally, the operator would not have to be flexible. The most efficient well design would be available and it could be replicated across the entire shale play. In such an ideal world, risk would be much easier to manage. However, this ideal would demand, for one, that the subsurface characteristics of any play be homogeneous. This is very unlikely; even the best plays will have a high probability of change in the subsurface characteristics. Furthermore, such a geological change may not be as foreseeable as it is for a conventional reservoir. In reality, when drilling a new well, the proposed well designs and fracturing programs may fail, and the operator will have to re-commence experimenting with techniques in the hopes of achieving commercially viable production levels.

To better appreciate such a shale project, imagine a number of drill pads equally spaced on one end of a sizable rectangular acreage. Attached to each drill pad are multiple wells that extend vertically down toward the shale formation. When approaching the shale formation, these wells begin to curve until they are running horizontally through the target area of the play. Placed like the teeth of a comb, these wells allow for optimal spacing of hydraulic fractures throughout the formation. As time elapses, more such multi-well pads populate the acreage as the project moves across the shale play, systematically fracturing and exploiting as much of it as possible. As it does so the operator attempts to always re-apply a selected number of well designs. While some wells move easily into the exploit phase, others may be transitioning between concept, pilot and exploit phases to cope with unforeseen subsurface characteristics.

New Risks

For a conventional project, the industry practice is well defined: drill one or two exploration wells, assess the results, create a development strategy to optimize production, install infrastructure to execute the plan, and maintain production. The project is linear. After the well is completed, the project risk drops dramatically. As long as there are no problems with the reservoir, the operator needs only to maintain equipment and keep production flowing. Nearing the end of the well's commercial production, when the reservoir is depleted, notable risk re–emerges. At this point, the operator engages in enhanced recovery strategies entailing additional capital investment and increased operating costs to maintain reservoir pressure until the reservoir is no longer commercially viable.

For an unconventional shale project, the subsurface risks play out differently. A greater number of wells need to be completed for commercial production. The cost of drilling more wells is multiplied by the fact that each well tends to be more expensive than a conventional one. This is because each needs to use horizontal drilling and hydraulic fracturing technologies. Accordingly, these projects have higher breakeven points and are more sensitive to risk.

Increased cost sensitivity is made more problematic because it is harder to predict the commercial viability of the acreage over the asset's life cycle. Shale plays rarely enjoy geological homogeneity across the play. Thus, at different locations within the play, the operator may have to invest more time, money, and effort to tease the hydrocarbons from the shale. These additional complications can make it difficult to predict costs.

Post completion, an operator of a successful conventional well tends to enjoy a time of more or less uninterrupted production from the reservoir's natural drive mechanism. Even after this, the operator can replace the natural drive artificially, extending the life of the asset. This is not to say that maintaining reservoir pressure will not have its complexities, just that a conventional well tends to have higher risk until it is completed and then the risk decreases dramatically during the production phase. By contrast, a shale play tends to have lower risk up front, but it tends to persist throughout the project's lifecycle. In other words, the risk profile tends to be flat. As a result, this continuing risk ensures that an operator of a shale project will not enjoy the same general risk profile as an operator of a successful conventional well.

Takeaways

There are at least three takeaways from comparing conventional and unconventional shale projects. First, the costs of unconventional projects are higher. Accordingly, such projects are more sensitive to risk. Second, although the geological risk of an unconventional project may be, on balance, lower than a conventional project, the risk does not tend to decrease, as it does for successful conventional projects. It follows that unconventional projects are not only more sensitive to risk, but the risk tends not to decrease over the life of the project. Third, while conventional asset life cycles are linear, unconventional asset life cycles may not be; they can move forward and backward through the phases in order to cope with changes in subsurface characteristics over the acreage. In sum, an unconventional project has higher costs, is more sensitive to risk, and sustains its level of risk over the asset's life cycle.

The Debate Over Model Rules

There are a number of debates as to which model rules are best suited for shale projects. This article introduces two of the main ones: Operator Control vs. Committee Control and Independent Operations vs. No Independent Operations.

Operator-Control vs. Committee-Control Model

For conventional projects, most domestic model agreements grant the operator sole authority over project management with only a few opportunities for the non-operators to contest its discretion. One such opportunity is that the non-operator can explain, using a prescribed process, how the operator could conduct operations more efficiently. If the suggestion is reasonable, the operator will have a set period of time to respond: choosing either to adopt the suggested mode of operation, or step aside and let the objecting party takeover management on the terms it prescribed in the complaint. If the operator steps aside, the objecting non-operator must act as operator on the prescribed terms for at least two years. Although never used all that effectively in practice, this requirement acts as a policing mechanism, ensuring that only reasonable demands will be placed upon the operator.

Another opportunity is the Authorizations For Expenditure (AFE) mechanism. If the operator selects a course of action and the total bona fide estimated cost of that action is more than a set amount (usually set at $50,000), then the operator is required to issue an AFE to the non-operators for approval. The AFE must contain sufficient information for the non-operators to make an informed decision. If a non-operator does not approve the AFE, this may trigger the independent operations mechanism (note that this mechanism is also called "exclusive operations" in some model agreements). Under this mechanism, those that want to continue with the project, as long as they are willing to assume the additional risk between them, can conduct the proposed operations without the non-participating parties.

Some, such as the Association of International Petroleum Negotiators (AIPN), suggest that this operator-control model is inappropriate for unconventional projects, because more decisions, well in excess of the traditional trigger amount for an AFE (i.e. $50,000), need to be made on an ongoing basis. The result is many more AFEs: each AFE representing a potential independent operation. Never knowing whether all the parties are financially committed to future actions reduces business certainty. This financial uncertainty can result in under-capitalization, since the higher costs of unconventional projects may require a greater risk appetite to go it alone.

One solution is to increase the set amount to trigger an AFE to $100,000 or $200,000. The downside of increasing the amount is that it will increase the discretion of the operator, and thus reduce the safeguard effect the AFE provides to non-operators. Ironically, this potential solution to the under-capitalization problem could lead to over-expenditure, because the operator can gamble with the investment of non-operators, and there are fewer safeguards over the operator's decisions.

In response to these concerns, the AIPN's 2014 Operating Agreement for Unconventional Resources (2014 UROA) offers a competing mechanism to operator-control. It employs the use of an operating committee, which usually features a voting threshold of 50-75% of the participating interests in the venture. The operator is beholden to the instructions of this committee and has only a limited discretion to act without that authority. This committee-control model grants non-operating parties greater capacity to contribute to management and helps to provide a mechanism for the creation and approval of annual budgets. When large and unforeseeable expenses arise, the committee-control model still provides non-operator consultation on an ad hoc basis, using AFEs on a much more limited basis. This largely locks in capital, and provides greater business certainty for such projects.

However, some drafters resist the committee model approach for a number of reasons, including in no small part that they perceive that the domestic users of their agreements are accustomed to, and prefer, how things are presently done. Furthermore, it is perceived that the committee approach increases opportunities for risk adverse parties to block development. This may or may not prove to be the case. Regardless, loyalty to the operator-control model creates a formidable challenge, that is: how to optimize development in a manner that avoids the increased threat of under-capitalization on one hand, but also the threat of over-expenditure on the other.

Independent Operations vs. No Independent Operations

When less than all parties are willing to fund a new project proposal, the independent operations mechanism may provide an opportunity for some members of the original joint venture, who have a larger risk appetite, to invest in a sub-consortium and push forward. This mechanism prevents any party from vetoing any proposed expansion of operations. If such a veto were allowed, the most risk adverse party could set the pace.

The parties can set the requirements for independent operations in a number of ways. For instance, it can be agreed that a party with an interest of less than a certain percentage of the total working interest (e.g. 5%) may not propose an independent operation. Another potential restriction could be that no such operation is permitted without the support of a minimum percentage of the total working interest (e.g. 25%). Another is that such operations may only be proposed after certain initial commitments are met under the original agreement. Such requirements can create a balance between the freedom to pursue profit and the ability to protect the joint venture as a whole.

When a party opts out of an independent operation, it does not necessarily lose the right to come back into the operation if the venture proves to be successful. In a successful independent operation, once the participating parties have recovered a multiple of costs (e.g. 400%), the non-participating parties start to get a share of production.

In conventional projects, not all independent operations are used for new exploration and drilling, some are for restoring, prolonging or enhancing the existing production of a well. That said, many independent operations result from disputes over new drilling opportunities and can be regarded as a kind of side bet. It is a side bet, because whether or not the independent operation pays out matters little to the success of the primary wells of the joint venture. So, in the domestic context, costs plus an additional bonus (e.g. 400% of costs) is an attractive stake for those with greater risk appetite. If they succeed in their wager, not only do they win, but also all parties to the venture win; and if they lose, only the risk-takers are out of pocket. This mechanism may have its critics, but on balance, few deny that it enhances the potential profitability of conventional projects in most cases.

In an unconventional project, things may play out differently. The disputes that arise as to further investment are rarely side bets, mere peripheral gambles; rather, they are integral to the project's success. If a party is allowed to elect not to participate (subject only to costs plus a penalty for re-entry), the non-participating party's election not to participate can be used as a weapon to unfairly shift more risk upon those, who the non-participating party knows are committed to ensuring that the project does not fail.

The remaining participating parties may choose, in retaliation, to under-capitalize to mitigate the extra risk/cost thrown upon them. As a result, under-capitalization may lead to less exploration, experimentation, and analysis. Accordingly, the operator might make less informed decisions as to drilling. This can result in suboptimal production, or in the worse case, the premature abandonment of the project. Either way, the project may suffer.

Although fears persist over allowing independent operations, the 2014 UROA has retained it, attempting to make it work by introducing safeguards, such as: (1) using annual budgets and work programs (reducing the opportunities for independent operations); (2) limiting reentry after a party opts out (preventing problematic de-risking strategies); and (3) adding further restrictions on their use (e.g. allowing such an operation on only one multi-well pad per quarter section per year).

Conclusion

This article has pointed to a few of the differences between conventional and non-conventional projects. Hopefully, it has also added to the current debate over what changes need to be made to model operating agreements, by offering some useful insights into the complexities in—and pitfalls of—modifying such agreements for unconventional shale projects.

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