Chapter 4

The New AAPl Form 610 JOA
Coalbed Methane Checklist:¹
Making the List and How to Check It Twice²

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Synopsis

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§ 4.01. Introduction.

Coalbed methane (CBM) was long considered to be a very dangerous nuisance. We all have heard the stories of the canaries in the coal mines and of the tragic loss of life due to CBM induced explosions. However, beginning in the 1980s, CBM’s value as a viable hydrocarbon resource was recognized and companies began exploration and development to extract it as the primary recoverable resource. Estimates of CBM reserves in the continental United States are conservatively placed at more than 700 trillion cubic feet (TCF), with perhaps 100 TCF recoverable with today’s existing technology. As of 2004, proved CBM reserves were 18,390 billion cubic feet (BCF), and accounted for nine percent of all domestic dry gas production. Is it any wonder, particularly given the recent increase in natural gas prices, why CBM exploration and development continue to burgeon?

The American Association of Petroleum (now Professional) Landman (AAPL) sanctioned the drafting of a uniform joint operating agreement first in 1956, known as the “Form 610.” It quickly became adopted as the industry standard. As a consequence of issues arising over the intervening years, and in an attempt to improve its contents, the Form 610 was revised by AAPL in 1977, 1982 and most recently in 1989. However, the Form 610 and all revisions thereto were drafted generally with conventional oil and gas exploration and development in mind. As outlined below, CBM exploration

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5 There are numerous articles addressing the history and development of the AAPL Form 610. See, e.g., Young, “Oil and Gas Operating Agreements: Producers 88 Operating Agreements, Selected Problems and Suggested Solutions,” 20 Rocky Mtn. Min. L. Inst. 197, 198-202 (Matthew Bender 1975); Wigley, “AAPL Form 610-1977 Model Form Operating Agreement,” 24 Rocky Mtn. Min. L. Inst. 693. (1978); and Reeves, “Significant Cases Governing the Onshore Operating Agreement,” 49 Inst. on Oil & Gas L. & Tax’n, Sec. 2.02 (Sw. L. Fdn. 1998).
and development have unique and distinct differences from conventional exploration and development.

Recognizing those differences, the AAPL in 2004 created a task force to make recommendations on how the Form 610 should be modified to address CBM exploration and development. This chapter addresses the Task Force’s efforts and resulting documentation ultimately adopted by AAPL’s governing Board of Directors.

§ 4.02. “Coalbed Methane (or CBM) 101.”

To understand why modifications to the Form 610 to address CBM were deemed necessary, the fundamentals of CBM and its extraction must be understood. Methane is bonded and held to the coal matrix by hydrostatic pressure. In order for the methane to be released from the matrix (desorption), the hydrostatic pressure must be reduced, i.e. the coal seams must be dewatered.6 In some fields, the pressure must be reduced to less than half of its original state.7

The defining difference between conventional and CBM development is therefore the required infrastructure. As one CBM expert has stated, expenditures for the infrastructure necessary to simply produce CBM wells, let alone determine their profitability, account for up to two-thirds of a prospect’s total costs.8 Another CBM expert has identified three infrastructure elements crucial to a successful CBM development: dewatering (subsurface communication), water disposal, and compression.9

The dewatering element is self-explanatory in light of the discussion above. Many wells must be drilled and strategically patterned to allow communication for quick and efficient dewatering. A large gap between wells

6 Allen, “Coalbed Methane Primer, 47 Landman No. 2 at Pg. 26 (March/April 2002)(hereinafter cited as Allen).
7 Testimony of Joseph McHenry, Senior Petroleum Engineer, Texaco Exploration and Production Inc., In Re Huntington (Shallow) CBM Unit, Docket No. 2001-007, Cause No. 245-2, Utah Board of Oil, Gas & Mining (March 28, 2001).
8 Id.
9 See Allen, supra note 6, at 28.
will destroy the ability to achieve subsurface communication and make it much more difficult, if not impossible, to dewater the reservoir. Thus, contrary to conventional well development, interference between CBM wells is required and desirable. CBM development should be thought of as the antithesis of pressure maintenance; a depressurization unit if you will. In addition, a larger land block is required to allow for such a sufficient amount of wells to be drilled.

So dewatering a reservoir is essential for CBM development, but what are you supposed to do with the water? Trucking? It’s a very expensive venture, especially given the usual large amounts of water produced. An evaporation pond program? This is a viable option unless you have an uncooperative landowner. In addition, there are permitting and other environmental considerations (such as treatment requirements before discharge). An injection well program is also a viable option but can be expensive and is only economical if kept at optimal capacity. This requires development on a larger scale (thus also requiring a larger land block). Reverse osmosis, especially in the arid West, is a desired option but is very expensive and may not always work.

Finally, as indicated, low reservoir pressure is essential to allow and maintain desorption; therefore gas pipeline pressure must also be extremely low. However, before acceptance into an interstate pipeline, the gas must be compressed. Centralized compression for use with many wells will run at capacity and be the most efficient and economical. Again, however, it requires several wells and a large acreage block.

§ 4.03. The Task Force Genesis.

CBM operators quickly became creative in trying to modify and tailor the Form 610 to fit their operations. Among some of the earlier modifica-

10 Id.
11 Id.
12 Id.
tions were the inclusion of gas gathering and water disposal facilities within the definition of those costs included within an authority for expenditure ("AFE") and for which non-consent penalties would apply. Other modifications included adding provisions authorizing allowing a single AFE for a multiple well grouping, which could include a well drilled strictly for purposes of dewatering and not production, and the application of non-consent penalties to the entire grouping ("basket payout"). Still others provided for complete forfeiture by a non-consenting party in a well or wells rather than mere assessment of non-consent penalties and striking any provision allowing a separate completion election. Other operators decided to use the Form 610 only as a template and write an entirely different form with provisions more analogous to the federal exploratory unit concept of annual plans of development.\textsuperscript{13} All of these efforts were somewhat piecemeal and varied from basin to basin.

In late 2002 or early 2003, the AAPL Forms Committee, which oversees the Form 610, was approached about the need to avoid this piecemeal approach and adopt a more standardized form for CBM exploration and development. Some on the committee initially believed a completely new version of the Form 610 would be required, but others argued that only a simple checklist outlining some modifications was required. Having failed to reach consensus, the committee referred the matter to the AAPL’s executive committee to appoint a Task Force to study the matter in detail, to make recommendations and to proceed with drafting based on its findings.

\textbf{§ 4.04. The Task Force and Its Efforts.}

In February, 2004, Craig Young, then president of AAPL, established the Coalbed Methane Joint Operating Agreement Task Force.\textsuperscript{14} Shortly after

\textsuperscript{13} See, e.g., 43 C.F.R. § 3186.1, § 10; see also Rocky Mountain Unit Operating Agreement Form 2 (Divided Interest) Article 7 (Rocky Mt. Min. L. Fdn. 1994).

\textsuperscript{14} In addition to the author, the Task Force was comprised of Arnold Schulberg, Hurricane, WV, Independent Landman and Attorney, who served as Task Force Chairman; Jim Dewbre, Houston, TX, Vice President of Land – Southwestern Energy Production Company; Max Eddington, Calgary, AB, Canada (formerly of Houston, TX), Landman – BP America Production Company; Paul Rote, Birmingham, AL, Landman – Energen Resources Corp. and
formation, the Task Force held its first telephone conference to confirm its mission and design an action plan to carry out its charged tasks. The first step was to identify contacts and then conduct a survey of companies actively involved with CBM plays about the following issues:

1) What version, if any, of the Form 610 was being utilized and why?

2) What modifications thereto were being made to account for CBM development?

3) What are the major areas of CBM development that should be addressed in a joint operating agreement? and

4) To request copies of modifications of and new provisions to the Form 610 for CBM operations previously or currently being used or, if a Form 610 was not being used, copies of the operating agreement form being utilized.

The Task Force received outstanding support and cooperation from those surveyed.15

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Jim Schaff, Denver, CO, Landman – Williams Production RMT Company. Luann Thomas, Oklahoma City, OK (formerly of Birmingham, AL), Landman – Samson Resources Corp. (formerly with GeoMet, Inc.), also served briefly with the Task Force and was of valuable assistance. Dorsey Roach, Tulsa, OK, Landman and Attorney – UnitPro Land Consultants, Inc. (formerly with Williams Production RMT Company), was later recruited to the Task Force to assist in making conforming changes to the 1989 version of the Form 610 (since he was actively involved in the drafting of that version). In addition to their CBM expertise, the members of the Task Force were chosen on the basis of their work in the diverse regions where domestic CBM development is occurring, including the Appalachian, Black Warrior, San Juan, Powder River and Uinta Basins and the analogous Fayetteville shale play.  

In addition to our respective employers, the Task Force members would like to publicly recognize and thank the following parties and their companies for their participation in the survey and input throughout this process: William Rainbolt and William Franklin – ConocoPhillips Company; James O’Malley, Jeff Niemeyer and Thomas Marranzino – Anadarko Petroleum Corporation; Joseph Stephenson – GeoMet, Inc. (formerly with Dominion Exploration & Production, Inc.); Terry Radney – Locke, Liddell & Sapp; Karla Bower – ConocoPhillips Company and on behalf of the Counsel for Petroleum Accountant Advisors Society (COPAS); Lester Zitkus – Equitable Production Company; and Michael Curry – Cotton, Bledsoe, Tighe & Dawson.
In conjunction with the AAPL annual meeting held in June, 2004, the Task Force members had their first face-to-face meeting to garner the results of the survey and modify the action plan accordingly. The results of the survey disclosed first that the 1982 version of the Form 610 was preferred by a wide margin over the 1989 version.\textsuperscript{16} Second, a checklist rather than an entirely new form was almost unanimously preferred. The areas of greatest concern of those polled were the up-front commitment for a large capital investment in infrastructure, appropriate risk allocation, and timing of completions due to de-watering and infrastructure construction.\textsuperscript{17}

The Task Force members then were divided into groups to draft provisions for a checklist responsive to these concerns, with a focus on the 1982 version first.\textsuperscript{18} Conforming revisions were made and the 1982 version checklist was submitted to the AAPL Board of Directors, which approved it at its quarterly meeting in September, 2005. The conforming 1989 version checklist was drafted shortly thereafter and likewise approved.

\section*{§ 4.05. The Checklist.}

\[1\] — Definitions.

Many law professors advise their first year students that good legal analysis starts with a review of definitions. Again, because of the unique aspects of CBM development, new and modified definitions were required for the checklist. Definitions are addressed in Article I of both the 1982 and

\textsuperscript{16} Among the reasons given for the stated preference were familiarity and comfort level and because of the perception, whether right or wrong, that the 1982 version is more “operator friendly.”

\textsuperscript{17} Numerous forms and provisions were provided which helped the Task Force tremendously in understanding the hows and whys behind the modifications that were being made. Of particular assistance were facility agreements addressing water disposal and gas gathering.

\textsuperscript{18} A checklist reflecting conforming changes to the 1989 version would then be made after agreement on the checklist for the 1982 version had been reached (thus leading to the recruitment of Dorsey Roach to the Task Force). No less than 15 telephone conferences and five face-to-face meetings later, the Task Force came up with its proposed checklist. It was once again sent out to industry contacts for review and comments. Several constructive responses were received and the Task Force had three more extensive telephone conferences to discuss them.
1982 versions of the Form 610. Many material definition modifications/additions contained in the checklist are addressed in Section 4.05[1]. The remaining material definitional changes are more appropriately set forth in the sections below addressing the various articles of the checklist to which they pertain.

[a] — “Coalbed Methane” and “Gob Gas.”

Both the 1982 and 1989 versions of the Form 610 contain a definition of “Oil and Gas.” The checklist first modifies this definition to include “coalbed methane” within that definition. Specifically, in the 1982 version checklist, the definition is modified [with the modifications highlighted] to read as follows:

The term ‘oil and gas’ shall mean, oil, gas casinghead gas, gas condensate, coalbed gas, coalbed methane gas and all other liquid or gaseous hydrocarbons and other marketable substances contained in, emitting from and/or produced therewith, unless an intent to limit the inclusiveness of this term is specifically stated.

Then, the following new definition of “coalbed gas or coalbed methane gas” is added:

[T]he occluded methane and/or all other liquid or gaseous hydrocarbons and other marketable substances contained in, emitting from or produced therewith or from coal deposits or any related, associated, or adjacent rock materials, including gob gas.19

As you will note, the term “gob gas” is included in the CBM definition. Gob gas is of particular importance to those with CBM operations in the

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19 The author’s committee notes are unclear as to from where or how this definition was derived (it is suspected it came from one of the forms submitted). The Task Force members all agreed that it was an excellent representative definition so it was utilized. To the original scrivener, this anonymous credit will have to suffice.
eastern and southern states for reasons evident by the following new definition set forth in the checklist:

[G]as, including but not limited to, coalbed methane gas, produced from the gob zone, being the area of fractured coal and rock created as the overburden caves into the unsupported mined-out void, and is: (1) released from residual coal in the primary seam, from the coal seams in the roof and floor, or from nearby mine workings; (2) “strata gas” that escaped from coal seams prior to mining activity and was trapped in non-coal strata; and/or (3) natural gas that originated in non-coal strata.20

Inclusion of the gob gas provisions of the checklist will be largely dependent upon whether the rightful owner of the gob gas will be a signatory.21

[b] — “Drill” and “Complete.”

The checklist also separates and excepts completion from the definition of drilling and provides two separate options for its definition, based on differing CBM completion techniques. Also, the definition of “drill” is more expansive than those usually utilized, by including roads and drillsite preparation. The definitions of these terms in the checklist are as follows:

The term ‘complete’ and/or ‘completion’ shall mean:

Option No.1: all operations, concluding with the release of the cavitation rig, or under-reaming operations, reasonably necessary and incident to the production of substances from a well and equipping through wellhead connections.

21 Ownership of gob gas has been the subject of litigation. See, e.g., NCNB Texas Nat’l Bank v. West, 631 So. 2d 212 (Ala. 1993).
Option No. 2: a single operation intended to complete a well as a producer of coalbed methane in one or more zones, including but not limited to, the setting of production casing, perforating, well stimulation and production testing conducted in such operation.

The term ‘drill’ shall mean all operations, including but not limited to, directional control and intentional deviation other than sidetracking, reasonable, necessary and incident to the drilling of a well to its projected depth, including preparation of roads and drillsite, testing and logging, but excluding completion operations.22

[c] — “Facilities” and “Wellsite Facilities.”

As already addressed, facilities are of major concern in CBM development. Centralized facilities, such as water disposal and gas gathering and treatment, must be distinguished from those facilities necessary to produce a single well. Generally, the distinguishing point is that of the wellhead meters. In recognition of the distinction, the Task Force adopted the following definition of “facilities” in the checklist:

[T]he facilities and infrastructure to be located on the lands within the Contract Area, including but not limited to water management facilities, production facilities, water and gas pipelines, power lines, creek crossings, access roads, compressor stations, ponds or other facilities required to produce, operate, transport treat and take care of coalbed methane gas and/or coalbed methane gas produced from or attributable to two or more wells located on the Contract Area.23

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22 Again, the author’s committee notes are unclear as to the source of the definition (it is suspected it came from one of the forms submitted). To the original scrivener, this anonymous credit will have to suffice.

23 This definition derived from a form used and submitted by GeoMet, Inc.
The term “wellsite facilities” is then defined in the checklist as follows:

[T]he equipment and facilities associated with any single well for the benefit of that well only.\(^{24}\)

Centralized facilities are then addressed separately in Article XV of the 1982 version and Article XVI of the 1989 version of the checklist and referenced attachments thereto, as outlined in Section 4.05[6] infra.

[2]— Net Beneficial Interest Option.

Article III of both the 1982 and 1989 versions addresses and sets forth the contractual interests of the parties in the defined contract area, \(i.e.\) establishes the interests of the parties in costs and production. Although CBM development has and can certainly continue to occur well-by-well on an established drilling and spacing unit basis, for the reason outlined under Section 4.02 supra, most CBM development should occur on a larger acreage block basis. Under these circumstances, there may be several working interest owners contributing leases with a wide variance of leasehold burdens. In order to account for these variances and to establish fixed cost (excepting centralized facilities) allocation, the Task Force agreed to provide a “net beneficial interest” option in the checklist.

Under this option, the parties agree to pool and set their contractual gross and net revenue interests across the contract area, essentially creating an undivided unit among the working interest owners; albeit, without a cross-conveyance of interests. The concept of “beneficial interest” indicates the relative value of the leased acreage to the working interest owner in the contract area.\(^{25}\) The concept has been successfully utilized in undivided federal exploratory units.\(^{26}\)

\(^{24}\) This is an original definition drafted by the Task Force.


In the checklist exhibit relating to this option, the working or “participating” interest of a party is defined as:

the sum of its cost bearing interest in each tract of land in the Contract Area calculated by multiplying its tract working interest times the total number of acres in such tract, divided by the total number of acres contained in the Contract Area.

The “beneficial” interest of a party is then defined as:

its share of all production from the Contract Area, expressed as a percentage or fraction, after deducting all existing burdens (meaning all non-cost bearing obligations measurable by or out of production, including but not limited to: lessor’s royalty, overriding royalty, production payments and the like payable thereon allocated according to the following formula:

the sum of its revenue interest in each tract of land in the Contract Area calculated by multiplying its tract gross working interest times its leasehold or mineral net revenue interest times the total number of acres in such tract, divided by the total number of acres contained in the Contract Area.27

These interests are fixed, with no re-determination except that a failure of title shall be an individual loss as set forth in Article IV of the main body of the Form 610 and shall result in the diminution of the interest of the affected party only.

A simple example of how this is intended to work is appropriate. Presume the Contract Area is comprised of two regular governmental sections (1,280 acres). Party A contributes a lease covering one section (640 acres) with a 12.5 percent landowner’s royalty burden (a net 87.5 percent), and Party B contributes a lease covering the remaining section (640 acres) with a 15

27 See AAPL JOA Form 610-1982 and AAPL JOA Form 610-1989.
percent landowner’s royalty and a five percent overriding royalty burden (a net 80 percent). Each party therefore has a 50 percent gross working or participation interest (640/1,280). However, their net beneficial interests are calculated as follows:

**Step 1:**

Party A - 87.5% net revenue interest x 640 acres = 560 net revenue acres  
Party B - 80% net revenue interest x 640 acres = 512 *net revenue acres*

Total = 1,072 net revenue acres

**Step 2:**

Party A – 560 net revenue acres/1,072 total net revenue acres = 52.24%  
Party B – 512 net revenue acres/1,072 total net revenue acres = 47.76%

Total = 100%

Thus, Party A has a net beneficial interest of 52.24% and Party B has a net beneficial interest of 47.76%. Production from the Contract Area then would be allocated as follows:

**Step 1:**

Party A Burdens – 12.5% x 640 acres/1,280 acres = 6.25%  
Party B Burdens – 20% x 640 acres/1,280 acres = 10%

Total = 16.25%

The total net revenue interest to be shared from the contract area (CANRI) is therefore is 83.75% (100% - 16.25%).

**Step 2:**

Party A – 52.24% (NBI) x 83.75% (CANRI) = 43.75%  
Party B – 47.76% (NBI) x 83.75% (CANRI) = 40%

Total = 83.75%

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28 This example was drawn from the discussions in Ashworth, “Beneficial Interests: Practical Use and Application,” 40 *Landman* No. 4, at Pg. 46 (May/June 1994). The reader is directly referred to the article as an excellent, more detailed resource on net beneficial interests and their application.
Drilling and Development.

Article VI of both the 1982 and 1989 versions of the Form 610 addresses drilling and development, the provisions where the “risk allocation” concerns expressed to the Task Force in the survey can be and were addressed. Specifically, the surveyed parties expressed the need to have a strong deterrent against non-participation in CBM development, given the up-front costs required, and conversely a proportionate reward for those who do agree to bear such costs. After review of the survey results and all of the forms submitted, the Task Force decided to provide three options for drilling and development, each with their own options for risk allocation. Each is addressed below.

[a] — Single Well.

As alluded to earlier, many of the first CBM operators simply utilized the Form 610 as is and drilled on a well-by-well basis with a set non-consent penalty applicable. Operations within the same contract area continue to develop under that contractual scheme with relatively few complications. Some of the comments received by the Task Force reflected a preference to maintain that option. Respecting that request, the Task Force left Article VI essentially unchanged as an option in the checklists. The only changes made were to expressly make participation in the initial well mandatory and to provide that the 100 percent non-consent penalty set forth in Article VI.B.2(a) of the 1982 version and Article VI.B.2(b)(i) of the 1989 version relating to subsequent operations is applicable to newly acquired “wellsite facilities” as previously defined,29 deleting the reference to “equipment beyond wellhead connections.”30

[b] — Pods.

The survey disclosed much of the CBM development across the nation is occurring on a concurrent multiple well drilling or “pod” basis. This

29 See § 4.05[1][c] supra.
30 See also § 4.05[4] infra concerning the elimination of a completion (casing point) election.
stems from the need for immediate interference between wells to de-water. The Task Force therefore created a second option for this more prevalent development practice.

Referring back to Article I of the checklist, the term ‘pod’ is defined as:

[A] grouping of two or more wells, which may include a well or wells whose specific purpose is to de-water, proposed for location within reasonable proximity of each other with the intent of optimizing interference to reduce the hydrostatic pressure and maximize production of coalbed gas from the collective area in which they are proposed for location.\(^{31}\)

The area of “proximity” is depicted on a plat. The plat for the initial pod is to be attached to the Form 610. Plats for subsequent pods are to be attached to and included as part of the AFE relating thereto.

Similar to the single well option, the checklist expressly mandates participation in the initial pod. However, unlike the single well option, additional optional ramifications for non-consenting subsequent operations are provided. The first option is a complete forfeiture of the non-consenting party’s interest in the pod area, as depicted on the related plat, in perpetuity. This may seem to some as an incredibly harsh consequence but it reflects the current practice of several operators and, to the Task Force members, reflects a reasonable deterrent/incentive in favor of participation and allocation of risk.

The second option retains the original Form 610 concept of an applicable percentage of recoupment or payout. However, recognizing the need for a collective well proposal, and particularly given that some of the wells within a proposed pod may be intended for de-watering only and therefore will not individually ever recoup the costs of drilling and operation through production, the Task Force adopted a “basket payout” approach. In other words,

\(^{31}\) This is an original definition drafted by the Task Force.
the non-consent penalty applies until recoupment of the costs of drilling and operating all wells within the pod. Similar to the single well option, the 100 percent non-consent penalty set forth in Article VI.B.2(a) of the 1982 version and Article VI.B.2(b)(i) of the 1989 version relating to subsequent operations is applicable to newly acquired “wellsite facilities” as previously defined, deleting the reference to “equipment beyond wellhead connections.”

One other issue arose under the pod option. The Task Force recognized the possibility of in-fill drilling within the pod area and how the parties would participate under those changed circumstances (presuming the forfeiture in perpetuity option was not selected). To address this situation, the checklist contains the following provisions:

\[ e.g. \text{ under Section VI.B.1(A) of the 1982 version} \]

Any party participating in a given pod may propose the drilling of in-fill wells, i.e. wells in excess of those provided for by a spacing order to more adequately drain a reservoir, within such pod’s collective area (as depicted on the related plat). The drilling shall be on a well-by-well basis and governed by the provisions of “Option 1: Single Well – Article VI.B” above; provided, however, that only those parties who have consented to all drilling and operations of the applicable pod as of the time such in-fill wells are proposed shall have the right to elect to participate in the drilling thereof and that all other parties’ rights shall instead be subject to the provisions of Subarticle VI.B.2(A) below.

\[ e.g. \text{ under Article VI.B.2(A) of the 1982 version} \]

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32 See § 4.05[1][c] supra.
33 See also § 4.05[4] infra concerning the elimination of a completion (casing point) election.
34 Definition taken from Kramer & Martin, 8 Williams & Meyers Oil and Gas Law, at 517 (2005).
An election not to participate in the drilling of a pod or any subsequent operations conducted thereon shall be deemed an election not to participate in the drilling of any in-fill wells within the collective area for the pod to which the Non-Consent election applied that are proposed any time prior to full recovery by the Consenting Parties of the Non-Consenting Party’s recoupment account. Any in-fill well drilled during the recoupment period shall be subject to recoupment of the same amounts relating to such well set forth in [(a) and (b) as to the 1982 version; (i) and (ii) as to the 1989 version] above, which amounts shall be added to the Non-Consenting Party’s existing recoupment account pertaining to the drilling of the pod. The aggregate amount of such account, after the addition of said amounts, must be recouped in its entirety before reversion of the Non-Consenting Party’s interest occurs as set forth below, i.e. the entire amount shall payout at one time, rather than on a well-by-well basis.\textsuperscript{35}

[c] — \textbf{Annual and Supplemental Plans of Development.}

Another multiple well option being utilized by some CBM operators, in lieu of pod development, is an annual plan of development. This option is analogous to the annual plans of development under a federal exploratory unit.\textsuperscript{36} This involves a budget and proposal for \textit{all} drilling and operations to occur during an entire year, with a proviso for supplementation if circumstances so require. This option probably should not be considered if there will be uncooperative small interest owners.

\textsuperscript{35} See AAPL JOA Form 610-1982 and AAPL JOA Form 610-1989.
\textsuperscript{36} See 43 C.F.R. § 3186.1, § 10; see also Rocky Mountain Unit Operating Agreement Form 2 (Divided Interest) Article 7 (Rocky Mt. Min. L. Fdn. 1994).
or owners that may, under applicable law, become a party to the operating agreement through force pooling proceedings.  

Referring back to Article I of the checklist, a “development plan” is defined as:

a description of the proposed operations and budget to be conducted on the Contract Area, or lands pooled or spaced therewith, during a calendar year. The development plan shall include sufficient detail to allow the Non-Operator to make an informed decision (it being understood that there shall be no option to non-consent an initial development plan), whether or not it wishes to participate as a Consenting Party in such development plan, including, without limitation:

An itemized budget of all planned expenditures, including wellsite facilities (as defined hereinbelow), to be charged to the joint account during the calendar year, it being understood that the proposed construction and budget for facilities other than wellsite facilities, shall not be included in the development plan but shall be included in the Facilities Agreement attached hereto as Exhibit ‘I.’

A forecast of the production profile and the costs to drill, complete, and develop the primary objectives of the development plan, including an estimate of the costs of any necessary wellsite facilities to be used, if then known.

To the extent known, a description of and the number of wells to be drilled detailing the primary objective(s), including the surface location, proposed bottom hole location, proposed depth and any other information relevant to the evaluation of the well(s).

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37 See, e.g., Utah Code Ann. § 40-6-6.5(2)(c).
Any other information in Operator’s possession relevant to an evaluation of the development plan or which Non-Operator may reasonably request.\textsuperscript{39}

The initial plan of development is to be attached to the Form 610 and approved concurrent with its execution. Mandatory participation therein is required. The initial plan or any subsequent approved annual development plan (ADP) may then be supplemented by a “supplemental development plan” (SDP), defined as:

[A] description of the proposed operations, including the costs thereof, to be conducted under this agreement which are in addition to the approved development during any given calendar year.\textsuperscript{40}

On or before November 1, an ADP is to be submitted to the parties to be voted upon at an annual meeting to be held within 30 days after submittal of the ADP. A similar process is followed for any SDP. A cap on the amount any one ADP or SDP may provide for may be specified. If the ADP or SDP receives the requisite percentage of approving votes, it becomes binding on the approving parties and the negative voting parties then become subject to optional non-consenting consequences.\textsuperscript{41}

The non-consenting options applicable to an ADP/SDP closely parallel those of the pod development. There is an option for forfeiture in perpetuity of all of the non-consenting party’s interest in the ADP/SDP and an option for a “basket payout” non-consent penalty, \textit{i.e.} reversion to the non-consenting party occurs only upon recoupment of the specified percentage of costs attributable to the entire ADP/SDP. Similar to the single well and pod options, the 100 percent portion of the non-consent penalty is applicable to newly

\textsuperscript{39} Definition taken from a form submitted by GeoMet, Inc.

\textsuperscript{40} \textit{Id.}

\textsuperscript{41} \textit{Id.}
acquired “wellsite facilities” as previously defined, deleting the reference to “equipment beyond wellhead connections.”

[d] — Completion Delay Option.
Especially with the initial development, there may be a need for the operator to delay completion because necessary infrastructure is not yet in place. The completion and shutting-in of CBM wells can be risky; the wells tend to water up again and may not perform to initial testing levels. For this reason, the Task Force included the following optional provision under all three drilling and development options:

Notwithstanding any other provision of this Article VI.B to the contrary, Operator may elect to delay completion of the well until such time that gas transportation facilities, including a gathering system, have been constructed, but in no event for a period longer than ____ without the written approval of ____% of the working interest.

Article VII.D of the 1982 version and Article VI.C of the 1989 version of the Form 610 provide options for a completion or casing point election. This is a second election, after participating in the initial drilling election, whether to participate in the completion of a well. These election provisions are primarily provided to address rank wildcat wells and allow the parties an opportunity to minimize losses if well logs and other pre-completion data are inconclusive. However, in CBM operations, extensive dewatering must

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42 See § 4.05[1][c] supra.
43 See also § 4.05[4] infra concerning the elimination of a completion (casing point) election.
45 Id. at 12-28.
occur before a well’s productivity can be determined and some drilling and completion techniques, such as cavity drilling and open hole completion, make it difficult to determine when a true “casing point” is reached.\footnote{Id.} For these reasons, many of the companies surveyed requested the completion election be eliminated and the Task Force, in the checklist, recommends that deletion or selection of the option without a completion election.


With the obvious reservoir for CBM being coal seams, concurrent and/or conflicting coal operations are always a distinct possibility. Depending on the priority of rights, whether by contract, deed, lease or adjudication by a court or regulatory body, the Operator may be requested and/or required to prematurely plug and abandon a CBM well to allow a “mine-through.” In recognition of this potential problem, the Task Force included the following provision in the checklist:\footnote{See, e.g., Articles VI.E and VII.D of the 1982 version.}

In the event Operator is requested by the coal owner or its lessee to plug a well which is reasonably necessary in Operator’s judgment or legally required in order for such coal owner or lessee to conduct its mining activities, Operator shall notify non-operators of such request. Any party objecting to such operation shall advise the other parties as to alternative remedies. Should a party concur with plugging the well, such party shall relinquish its interest in the well to the objecting party or parties, if any, and bear no further costs associated with such well.\footnote{This provision was based in part on Williams, supra note 40, at pages 12-28-29 and12-51.}


As might be expected, the most pressing issue for Task Force consideration, centralized facilities, was also the one with which the Task Force
members struggled the most. Initial plans were to provide a sample facilities agreement with the checklist. However, after the survey and based on review of sample facilities agreements provided to it, the Task Force concluded that there just were too many variables tied to an individual CBM development for a sample facilities agreement to have much value or use in the context of this portion of its charged task. The Task Force therefore decided to add special clauses to Article XV of the 1982 version and Article XVI of the 1989 version of the Form 610 and provide separate drafting checklists for two types of facilities arrangements: jointly owned or separately owned. The primary facilities to be addressed are, for the reasons outlined above, gas gathering and water disposal.

The Article XV/XVI modifications contained in the checklist first distinguish the two types of facilities arrangements. Under the jointly owned facilities arrangement, the parties will have equity ownership in all non-wellsite facilities. Under the separately owned facilities arrangement, the party or parties have no equity ownership in the facilities and instead enter into a fee based arrangement with the operator and/or other parties which do own the facilities. To the extent a party is made subject to the joint operating agreement through a force pooling order,49 the separately owned facilities arrangement is the only option available.

As to those who are eligible for the joint ownership option, the Article XV/XVI checklist modification first requires notice by a party wishing to construct such facilities to the other parties and then provides as follows:

Each Party receiving such notice shall have the right to participate in the construction, operation and ownership of such facilities by assuming its proportionate share of the obligations thereof and paying the costs attributable thereto. Failure to respond to the party proposing such construction within _______ (__) days of receipt of a detailed Authority For Expenditure (AFE), or separate notice given to the proposing

49 See, e.g., Utah Code Ann. § 40-6-6.5(2)(c) (West 2006).
part of an election not to participate, shall act as a complete, permanent forfeiture of all right, title and interest in and to the proposed facilities, including any future expansions thereto. In addition to the remedies available to Operator under Article VII.B (Liens and Payment Defaults) [1982 version] hereof, failure of a participating party to pay any invoice for capital costs as set forth in such AFE within (__) days of receipt thereof may be deemed, at the sole election of Operator, as a permanent forfeiture of that party’s right, title and interest in and to the proposed facilities, including any future expansions thereto.\footnote{See AAPL JOA Form 610-1982 and AAPL JOA Form 610-1989.}

Parties electing to participate shall be governed by the terms and conditions of the Jointly Owned Facilities Agreement attached hereto as Exhibit “__”

…[A]ny party deemed a non-participating party under the preceding paragraphs shall be given the option to enter into the Separately Owned Facilities Agreement attached hereto as Exhibit “__.”

The Article XV/XVI modifications contained in the checklist then conclude with the following:

Article VI.B.2 (Operations by Less Than All Parties) [1982 version] shall have no application whatsoever to the proposed operations and assets under this Article XV [1982 version].

Notwithstanding anything in the main body of this agreement to the contrary, all facilities other than wellsite facilities shall be governed by this Article XV [1982 version] and the Facilities Agreement Exhibit(s) applicable by virtue of its provisions. In the event of any conflict as to such facilities, the terms
and conditions of this Article and the Facilities Agreement Exhibit(s) applicable by virtue of its provisions shall prevail over the terms of the main body of this agreement and any other exhibits attached hereto.\(^{51}\)

As indicated, the checklist only provides drafting checklists for consideration; the referenced “Facilities Agreements” still actually must be drafted. With respect thereto, first and foremost, both legal and accounting advice should be sought concerning the proper corporate/partnership structure for any facilities ownership and the tax consequences relating thereto. Key drafting points set forth in the checklist for jointly owned facilities include setting voting control and approval percentages, non-consent ramifications (beyond the initial AFE expenditures), parameters on transfers of interests (e.g. no severance of system ownership from ownership of the wells, preferential rights to purchase, etc.), defining cost allocation and accounting procedures (including possible use of the COPAS Facility Form AG-4) and system expansions and future implied expenditures. Key drafting points set forth in the checklist for separately owned facilities include setting the fees (per barrel of water disposed/per mcf gas gathered, etc.), whether use of the facilities is on a firm or interruptible basis (use depending upon capacity), billing and reporting requirements, and licensure of non-equity owner’s rights-of-way for use in connection with the facilities.

§ 4.06 Conclusion.

A few miscellaneous points must be made. First, the Task Force received many suggestions and other sample modifications to the Form 610 that were not CBM specific. Those suggestions and modifications were sent on to the AAPL Forms Committee for consideration in a future modification/revision of the Form 610. Second, the review process disclosed that many of those surveyed would not utilize the checklist \textit{in toto} but would pick and choose certain provisions. This is exactly why the Task Force structured the

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\(51\) \textit{Id.}
checklist as it appears, *i.e.* to allow that flexibility. Finally, full and complete copies of both the 1982 and 1989 versions of the checklist may be obtained directly from AAPL.52

As with any contract template, the checklist is intended to be an evolving document, not the “last word” on the subject. As CBM development and technology evolves, so too must the checklist. Further review and suggestions to AAPL on its improvement will always be welcome. However, it is the Task Force’s hope and desire that the current checklist will be of immediate assistance to operators and non-operators alike, and set some common ground for negotiation of their agreement for joint CBM operations.

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52 As of the drafting of this chapter, the checklist was available through AAPL’s website (www.landman.org); click first on “Landman Tools” on the navigation bar and then on “Forms and Contracts.”