**STATE OF OHIO**
**DEPARTMENT OF NATURAL RESOURCES**
**DIVISION OF OIL AND GAS RESOURCES MANAGEMENT**

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| In re the Matter of the Application of Antero | : | |
| Resources Corporation for Unit Operation | : | |
| | : | Application Date: May 29, 2014 |
| Siberian Unit | : | REVISED: September 4, 2014 |
| | : | |

# REVISED APPLICATION

Pursuant to Ohio Revised Code Section 1509.28, Antero Resources Corporation ("Antero"), hereby respectfully requests the Chief of the Ohio Department of Natural Resources' Division of Oil and Gas Resources Management ("Division") to issue an order authorizing Antero to operate the Unitized Formation and applicable land area in Noble and Monroe Counties, Ohio (hereinafter, the "Siberian Unit") as a unit according to the Unit Plan attached hereto and as more fully described herein.

Antero Resources Corporation is a Corporation organized under the laws of the State of Delaware. Antero has its principal office at 1615 Wynkoop Street, Denver, Colorado 80202 and local offices at 2335 State Route 821, Broughton Building #14, Marietta, OH 45750. Antero is an exploration and production company engaged in the exploitation, development, and acquisition of natural gas, natural gas liquids and oil properties located in the Appalachian Basin and is registered in good standing as an "owner" with the Division.

Antero designates to receive service, and respectfully requests that all orders, correspondence, pleadings and documents from the Division and other persons concerning this filing be served upon, the following:

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Katerina E. Milenkovski (0063314)
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## I. LEGAL REQUIREMENTS

### A. Legal Standard

Ohio Revised Code § 1509.28 requires the Chief of the Division to issue an order providing for the unit operation of a pool – or a part thereof – when the applicant shows that it is reasonably necessary to increase substantially the ultimate recovery of oil and gas, and the value of the estimated additional resource recovery from the unit's operations exceeds its additional costs. *See* Ohio Rev. Code § 1509.28(A). The Chief's order must be on terms and conditions that are just and reasonable and prescribe a plan for unit operations. *See* Ohio Rev. Code § 1509.28(A).

As is shown below and in the various attachments hereto, Antero makes this request for the purpose of substantially increasing the ultimate recovery of oil and natural gas, including related liquids, from the Unitized Formation, and to protect the correlative rights of unit owners, consistent with the public policy of Ohio to conserve and develop the state's natural resources and prevent waste.

### B. Application Contents

Pursuant to the Ohio Department of Natural Resources, Division of Oil and Gas Resources Management's September 13, 2013 Unitization Application Guidelines, the following information must be contained within an application for unitization.

1. A cover letter requesting unitization.

   This document fulfills this purpose.

2. An affidavit attesting that the applicant is the owner (as defined in R.C. 1509.01(K)) of at least 65% of the land overlying the pool that is the subject of the unitization request.

   *See* Exhibit 5.

3. A summary of the request for unitization that includes all of the following information:

- A statement describing the reasons why unitization is necessary;
- A description of the plan for development of the unit;
- An identification of the geologic formation(s) to be developed;
- An estimate of the value of the recovery of oil and gas for each well proposed to be drilled in the unit area;
- An estimate of the cost to drill and operate each well in the proposed unit;
- A designated contact person for the applicant for communication purposes with the Division, including legal counsel for the applicant (if applicable).

*See* Section II of this Application, infra. In addition, company contacts are listed above. *See also* prefiled testimony of Brandon Binford, Hal Hogsett, and Sloane Ford, attached as Exhibits 2, 3 and 4, respectfully.

4. A list identifying all unleased mineral owners that includes the name, valid address, parcel number, and respective acreage of each unleased owner. If an unleased mineral owner is a corporation or other business entity, the name of a contact person within that corporation or business.

   *See* Exhibit 1-A.3 to Unit Agreement, attached to this Application as Exhibit 1.

5. A list identifying all mineral owners in the unit, leased or unleased, that includes the name, valid address, parcel number, and respective acreage of each owner. If a mineral owner is a corporation or other business entity, the name of a contact person within that corporation or business.

   *See* Exhibit 1-A.1 to Unit Agreement, attached to this Application as Exhibit 1.

6. A list identifying all uncommitted working interest owners in the unit, leased or unleased, that includes the name, valid address, parcel number, and respective acreage of each owner. If a mineral owner is a corporation or other business entity, the name of a contact person within that corporation or business.

   Not Applicable.

7. A map on a scale of 1”=1000’ that shows all of the following:

- The boundary of the proposed unit area;
- The proposed location of the well pad and wells to be drilled;
- The tracts of land within the unit area that are leased to the applicant, shown in yellow;
- The tracts of land within the unit area that are unleased, shown in red;
- The tracts of land within the unit area that are leased to other operators (i.e. uncommitted working interest owners), including an identification of the operators, shown in green;
- A five hundred foot boundary around each property in the unit that is not leased by the applicant or that is not subject to an agreement with the applicant;
- Identification of each tract within the unit area by parcel number.

*See* Exhibit 4-A, attached to this Application as part of Exhibit 4.

8. An aerial photograph on a scale of 1”=1000’ that shows all of the following:

- The boundary of the proposed unit area;
- The proposed location of the well pad and wells to be drilled;
- The tracts of land within the proposed unit area that are unleased;
- Identification of each tract within the unit area by parcel number.

*See* Exhibit 4-B, attached to this Application as part of Exhibit 4.

9. A gamma ray-density geophysical type log identifying the proposed geological formations to be produced.

   *See* Exhibit 2-B, attached to this Application as part of Exhibit 2.

10. A cross-section showing the applicable formations that the applicant is proposing to drill into and produce from in the unit area.

    *See* Exhibit 2-A, attached to this Application as part of Exhibit 2.

11. A map showing all existing units adjacent to the unit proposed in the application with an identification of any permitted, drilled, and/or producing wells in the existing units.

    *See* Exhibit 4-C, attached to this Application as part of Exhibit 4.

    If reserve calculations are based upon other existing wells in the vicinity of the proposed unit, an exhibit showing the locations of the well(s) to the proposed unit area and an identification of the wells by name and permit number.

    *See* Exhibit 2-A.

12. A statement in the form of an affidavit that gives a detailed account of the attempts to lease the unleased properties. The statement must include:

    - The dates of all attempts;
    - The person who was contacted, how contact was made, and by whom;
    - Any joint venture or farmout proposal to another operator, if applicable.

    *See* Exhibit 4-D, attached to this Application as part of Exhibit 4.

13. A copy of a joint operating agreement for working interest partners, if applicable.

    Not applicable.

## II. SUMMARY OF REQUEST FOR UNITIZATION

### A. Project Description

The Siberian Unit is located in Noble and Monroe Counties, Ohio, and consists of thirty-seven (37) separate tracts of land. See Exhibits 1-A.1 and 1-A.2 of the Unit Agreement (showing the tract participations and plat, respectively). The total land area in the Siberian Unit is approximately 702.245 acres and, at the time of this Application, Antero has the right to drill on and produce from approximately 702.181 acres of the proposed unit – i.e., more than Ninety-Nine percent (99%) of the unit area, well above the sixty-five percent (65%) threshold required by Ohio Revised Code § 1509.28.

As more specifically described herein, Antero seeks authority to drill and complete five horizontal wells in the Utica/Point Pleasant Formation ("the Unitized Formation") from a single well pad located on the North border of the unit to efficiently test, develop, and operate the Unitized Formation for oil, natural gas, and related liquids production. The "Unitized Formation" consists of the subsurface portion of the Unit Area (i.e., the lands shown on Exhibit 1-A.2 and identified in Exhibit 1-A.1 to the Unit Agreement) at a depth located from fifty feet above the top of the Utica Shale to fifty feet below the base of the Point Pleasant formation, and frequently referred to as the Utica/Point Pleasant formation. The evidence presented in this Application establishes that the Unitized Formation is part of a pool and thus an appropriate subject of unit operation under Ohio Rev. Code § 1509.28.[1] Additionally, that evidence establishes that the Unitized Formation is likely to be reasonably uniformly distributed throughout the Unit Area – and thus that it is reasonable for the Unit Agreement to allocate unit production and expenses to separately owned tracts on a surface acreage basis.[2]

B. Justification for Unitization

The evidence presented in this Application establishes that unit operations are reasonably necessary to increase substantially the ultimate recovery of oil and gas from the lands making up the Siberian Unit. It also demonstrates that unitized operation protects the correlative rights of all of the owners within the proposed Unit, and serves to further Ohio's public policy to conserve and develop the State's natural resources and prevent waste of the same.

The Unit Agreement contemplates the drilling of five (5) horizontal wells from a single well pad, with laterals in length of approximately 9,400 feet. Antero estimates that the ultimate recovery from this unit development could be as much as 91.0 Bcfe from the Unitized Formation. Absent unit development contemplated in the unitized project, the recovery would be substantially less: First, the evidence shows that it is unlikely that vertical development of the unit would ever take place because it is likely to be uneconomic – resulting in potentially no resource recovery from portions of the Unitized Formation. Second, avoiding unleased tracts by relying on shorter horizontal laterals to develop the Unitized Formation underlying the Siberian Unit would result in a substantially lower ultimate recovery of oil and gas, as it would strand

[1] A "pool" is defined under Ohio law as "an underground reservoir containing a common accumulation of oil or gas, or both, but does not include a gas storage reservoir." Ohio Rev. Code § 1509.01(E). See also Geology testimony, Exhibit 2.
[2] *See* Exhibit 2.

approximately 15.1 Bcfe of the total estimated reserves, unlikely to ever be developed.[3] Antero estimates that the ultimate recovery of reserves will increase by approximately 20% from 75.9 Bcfe to 91.0 Bcfe if the unit is developed utilizing the proposed unit development.[4]

The capital expense associated with developing the unitized project is $74.1 million, as compared to $64.7 million for the un-unitized project. The value of hydrocarbons expected to be recovered from the proposed unit is $94.7 million as compared to $76.2 million that could be recovered without unit operations. In other words, for an additional $9.4 million in capital expenditure, Antero could recover hydrocarbons valued at more than $18.5 million.[5] Thus, the economic benefits of unitization far outweigh the additional costs necessary for unit development.

C. Unitized Operations

The proposed unit operations would be governed by the Unit Agreement, attached to this Application as Exhibit 1. The Unit Agreement allocates unit production and expenses based upon each tract's surface acreage participation in the unit. The Unit Agreement also offers those parties who have not voluntarily entered into a lease agreement by the date of the hearing on this application two options:

(1) Upfront consideration of $7,000 per acre plus an 18% royalty [High Bonus Option] of the oil and gas produced from any well drilled pursuant to the Order, free and clear of all costs, expenses and risks incurred in connection with the drilling and completing any such well; provided that such royalty shall be payable only as to the proportionate amount the acreage placed into the unit bears to the total acreage in the unit; or

(2) Upfront consideration of $6,000 per acre plus a 20% royalty [High Royalty Option] of the oil and gas produced from any well drilled pursuant to the Order, free and clear of all costs, expenses and risks incurred in connection with the drilling and completing any such well; provided that such royalty shall be payable only as to the proportionate amount the acreage placed into the unit bears to the total acreage in the unit.

[3] *See* Reservoir Engineer Testimony, Exhibit 3.
[4] *Id.*
[5] *Id. See*, in particular, Exhibit 3-A.

The two options provided represent the current market value of leasing in this unit, which was determined by looking at open market transactions over the past year within the unit.[6] These options would allow Antero to develop this unit as planned and in the most efficient way possible, thus avoiding waste of natural resources that would otherwise be stranded. Allowing Antero to fully develop this Unit as planned would afford those parties who have leased their mineral interests and who want to participate in the unit the benefit of their bargain, and would also provide the unleased mineral owners with fair compensation for the inclusion and development of their minerals. Therefore, both options are "just and reasonable" as required by the statute.

The interest relinquished under either of the above options would be limited in depth and time as to the unitized formations and the term of the Unitization Order. Moreover, there would be no surface operations authorized unless specifically agreed to by Antero and the unleased owner. If an unleased party does not make a selection within the 30 day timeframe, we request that the Chief's Unitization Order treat the unleased party as if it had selected the High Bonus Option. Finally, where the Unit Agreement conflicts with any Unitization Order issued by the Chief, the Unitization Order shall control and govern the operations within the Unit.

For all of the foregoing reasons, as further supported by the various attached exhibits, affidavits and prepared testimony, Antero maintains that operation as a Unit is reasonably necessary to increase substantially the ultimate recovery of oil and gas and that the value of that additional recovery exceeds its additional cost, thereby meeting the statutory requirement for unitization under ORC 1509.28. Operating the Siberian Unit as proposed would be just and reasonable and would protect the correlative rights of all of the parties involved, as well as serve the state's public policy interests with respect to oil and gas development and conservation. Thus, Antero respectfully requests that the Chief authorize the Siberian Unit as proposed.

Respectfully submitted,

______________________________

R. Neal Pierce (0028379)
Katerina E. Milenkovski (0063314)
Ryan S. Bundy (0090027)

[6] *See* Landman Testimony, Exhibit 4.

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Attorneys for Applicant,
Antero Resources Corporation

**UNIT AGREEMENT**

**SIBERIAN_UNIT**
**MARION AND SENECA TOWNSHIPS**
**NOBLE AND MONROE COUNTIES, OHIO**

**THIS AGREEMENT**, entered into as of May 29, 2014, by the parties subscribing, ratifying, approving, consenting to, or bound to the original of this instrument, a counterpart thereof, or other instrument agreeing to become a party hereto; and by those parties participating as a result of an order issued by the Division of Oil and Gas Resources Management ("Division") pursuant to Ohio Revised Code Section 1509.28.

**W I T N E S S E T H:**

**WHEREAS**, in the interest of the public welfare and to promote conservation and increase the ultimate recovery of oil, natural gas, and other substances from the Siberian Unit, in Marion and Seneca Townships, Noble and Monroe Counties, Ohio, and to avoid waste and protect the correlative rights of the owners of interests therein, it is deemed necessary and desirable to enter into and approve this Agreement to create and establish a unit comprising the Unit Area under the applicable laws of the State of Ohio to unitize the Oil and Gas Rights in and to the Unitized Formation in order to conduct Unit Operations as herein provided; and,

**WHEREAS**, this Agreement allocates responsibility for the supervision and conduct of Unit Operations, and responsibility for the payment of Unit Expenses, to Working Interest Owners based upon each owner's pro rata interest in the unit acreage;

**NOW THEREFORE**, in consideration of the premises and of the mutual agreements herein contained, it is agreed and approved as follows:

**ARTICLE 1: DEFINITIONS**

As used in this Agreement:

**Effective Date** is the time and date this Agreement becomes effective as provided in Article 11.

**High Bonus Lease Option** means the option afforded by the Chief's Unitization Order to those Persons who were unleased as of the hearing on this Unit Application to enter into a lease providing a $7,000/acre bonus and an 18% royalty, governed by the terms of the form lease attached hereto as Exhibit 1-B.

**High Royalty Lease Option** means the option afforded by the Chief's Unitization Order to those Persons who were unleased as of the hearing on this Unit Application to enter into a lease providing a $6,000/acre bonus and a 20% royalty, governed by the terms of the form lease attached hereto as Exhibit 1-B.

**Oil and Gas Rights** are the rights to investigate, explore, prospect, drill, develop, market, transport, and operate within the Unit Area for the production of Unitized Substances, or to share in the production so obtained or the proceeds thereof, including without limitation the conducting of exploration, geologic and/or geophysical surveys by seismograph, core test, gravity and/or magnetic methods, the injecting of gas, water, air or other fluids into the Unitized Formation, the installation, operation and maintenance of monitoring facilities, the laying of pipelines, building of roads, tanks, power stations, telephone lines, and/or other structures.

**Person** is any individual, corporation, partnership, association, receiver, trustee, curator, executor, administrator, guardian, fiduciary, or other representative of any kind, any department, agency, or instrumentality of the state, or any governmental subdivision thereof, or any other entity capable of holding an interest in the Unitized Substances or Unitized Formation.

**Royalty Interest** means a right to or interest in any portion of the Unitized Substances or proceeds from the sale thereof other than a Working Interest.

**Royalty Owner** is a Person who owns a Royalty Interest in the Unit. Royalty Owners include those Persons who obtained their Royalty Interest by selecting either the High Bonus Lease Option or the High Royalty Lease Option pursuant to the Unitization Order of the Commission, or who failed to make a selection within the allotted time and were thus deemed to have selected the High Bonus Lease Option.



EXHIBIT 1

**Tract** means the land identified by a tract number in Exhibit 1-A.1 attached hereto.

**Tract Participation** means the fractional interest shown on Exhibit 1-A.1 attached hereto for allocating Unitized Substances to a Tract.

**Unit** means the Siberian Unit, located in Marion and Seneca Townships, Noble and Monroe Counties, Ohio.

**Unit Area** means the lands shown on the plat attached as Exhibit 1-A.2 and identified on Exhibit 1-A.1, including also areas to which this Agreement may be extended as herein provided.

**Unit Equipment** means all personal property, lease and well equipment, plants, and other facilities and equipment taken over or otherwise acquired for the unit account for use in Unit Operations.

**Unit Expense** means all cost, expense, investment and indebtedness incurred by Working Interest Owners or Unit Operator pursuant to this Agreement and any Unit Operating Agreement governing the Working Interest Owners, for or on account of Unit Operations, but shall not include post-production costs attributable to Royalty Owner interests.

**Unitized Formation** means the subsurface portion of the Unit Area located from fifty feet above the top of the Utica Shale (at an approximate depth of 7,995 feet) to fifty feet below the base of the Point Pleasant formation (at an approximate depth of 8,100 feet).

**Unit Operations** are all operations conducted pursuant to this Agreement

**Unit Operator** means Antero Resources Corporation**.**

**Unit Participation** is the sum of the interests obtained by multiplying the Working Interest of a Working Interest Owner in each Tract by the Tract Participation of such Tract.

**Unitized Substances** are all oil, gas, gaseous substances, sulfur, condensate, distillate, and all associated and constituent liquid or liquefiable hydrocarbons within or produced from the Unitized Formation.

**Working Interest** means an interest in Unitized Substances in the Unit Area by virtue of a lease, operating agreement, fee title, or otherwise, including a carried interest, the owner of which is obligated to pay, either in cash or out of production or otherwise, a portion of the Unit Expense.

**Working Interest Owner** is a Person who owns a Working Interest.

## ARTICLE 2: CREATION AND EFFECT OF UNIT

**Oil and Gas Rights Unitized**. All Royalty Interests and Working Interests in Oil and Gas Rights in and to the lands identified on Exhibits 1-A.1 and 1-A.2 are hereby unitized insofar as, and only insofar as, the respective Oil and Gas Rights pertain to the Unitized Formation, so that Unit Operations may be conducted with respect to the Unitized Formation as if the Unit Area had been included in a single lease executed by all Royalty Owners, as lessors, in favor of all Working Interest Owners, as lessees, and as if the lease contained all of the provisions of this Agreement. As between Working Interest Owners, the terms of individual Unit Operating Agreements supersede the terms of this Unit Agreement where the terms conflict.

**Personal Property Excepted**. All lease and well equipment, materials, and other facilities heretofore or hereafter placed by any of the Working Interest Owners on the lands covered hereby shall be deemed to be and shall remain personal property belonging to, and may be removed by, Working Interest Owners with the prior consent of Unit Operator. The rights and interests therein, as among Working Interest Owners, are set forth in the individual Unit Operating Agreements executed by the Working Interest Owners.

**Operations**. If an order is issued granting Unit Operator the authority to conduct Unit Operations, the operations conducted pursuant to the order of the chief shall constitute a fulfillment of all the express or implied obligations of each lease or contract covering lands in the unit area to the extent of that compliance with such obligations cannot be had because of the order of the chief.

**Continuation of Leases and Term Interests**. Unit Operations conducted upon any part of the Unit Area or production of Unitized Substances from any part of the Unitized Formation, except for the purpose of determining payments to Royalty Owners, shall be considered as operations upon or production from each portion of each Tract, and such production or operations shall continue in effect each lease or term, mineral or Royalty Interest, as to all Tracts and formations covered or affected by this Unit Agreement just as if such Unit Operations had been conducted and a well had been drilled on and was producing from each portion of each Tract. It is agreed that each lease shall remain in full force and effect from the date of execution hereof until the Effective Date, and thereafter in accordance with its terms and this Agreement.

**Titles Unaffected by Unitization**. Nothing herein shall be construed to result in any transfer of title to Oil and Gas Rights by any Person to any other Person or to Unit Operator.

**Pre-existing Conditions in Unit Area**. Working Interest Owners shall not be liable for or assume any obligation with respect to (i) the restoration or remediation of any condition associated with the Unit Area that existed prior to the Effective Date of this Agreement, or (ii) the removal and/or plugging and abandonment of any wellbore, equipment, fixtures, facilities or other property located in, on or under the Unit Area prior to the Effective Date of this Agreement. Working Interest Owners reserve the right to elect, but shall not have the obligation, to use for injection and/or operational purposes any nonproducing or abandoned wells or dry holes, and any other wells completed in the Unitized Formation.

## ARTICLE 3: UNIT OPERATIONS

**Unit Operator**. Unit Operator shall have the exclusive right to conduct Unit Operations, which shall conform to the provisions of this Agreement and any Unit Operating Agreements.

**Unit Expenses**. Except as otherwise provided in a Unit Operating Agreement governing the rights and obligations of Working Interest Parties, Unit Expenses shall be allocated to each Tract in the proportion that the surface acres of each Tract bears to the surface acres of the Unit Area, and shall be paid by the respective Working Interest Owners. Unit Expenses shall be determined in accordance with the Council of Petroleum Accountants Societies Accounting Procedure for Joint Operations ("COPAS"), attached hereto as Exhibit C.

## ARTICLE 4: TRACT PARTICIPATIONS

**Tract Participations**. The Tract Participation of each Tract is identified in Exhibit 1-A.1 and shall be determined solely upon an acreage basis as the proportion that the Tract surface acreage bears to the total surface acreage of the Unit Area. The Tract Participation of each Tract has been calculated as follows: SURFACE ACRES IN EACH TRACT DIVIDED BY THE TOTAL SURFACE ACRES WITHIN THE UNIT AREA. The Tract Participations as shown in Exhibit 1-A.1 are accepted and approved as being fair and equitable.

## ARTICLE 5: ALLOCATION OF UNITIZED SUBSTANCES

**Allocation of Unitized Substances**. All Unitized Substances produced and saved shall be allocated to the several Tracts in accordance with the respective Tract Participations effective during the period that the Unitized Substances were produced. The amount of Unitized Substances allocated to each Tract, regardless of whether the amount is more or less than the actual production of Unitized Substances from the well or wells, if any, on such Tract, shall be deemed for all purposes to have been produced from such Tract.

**Distribution Within Tracts**. The Unitized Substances allocated to each Tract or portion thereof shall be distributed among, or accounted for to, the Persons entitled to share in the production from such Tract or portion thereof in the same manner, in the same proportions, and upon the same conditions as they would have participated and shared in the production from such Tract, or in the proceeds thereof, had this Agreement not been entered into, and with the same legal effect. If any Oil and Gas Rights in a Tract hereafter become divided and owned in severalty as to different parts of the Tract, the owners of the divided interests, in the absence of an agreement providing for a different division, shall share in the Unitized Substances allocated to the Tract, or in the proceeds thereof, in proportion to the surface acreage of their respective parts of the Tract. Any royalty or other payment which depends upon per well production or pipeline runs from a well or wells on a Tract shall, after the Effective Date, be determined by dividing the Unitized Substances allocated to the Tract by the number of wells on the Tract capable of producing Unitized Substances on the Effective Date; however, if any Tract has no well thereon capable of producing Unitized Substances on the Effective Date, the Tract shall, for the purpose of this determination, be deemed to have one (1) such well thereon.

## ARTICLE 6: USE OR LOSS OF UNITIZED SUBSTANCES

**Use of Unitized Substances**. Working Interest Owners may use or consume Unitized Substances for Unit Operations, including but not limited to, the injection thereof into the Unitized Formation.

**Royalty Payments**. No royalty, overriding royalty, production, or other payments shall be payable on account of Unitized Substances used, lost, or consumed in Unit Operations.

## ARTICLE 7: TITLES

**Warranty and Indemnity**. Each Person who, by acceptance of produced Unitized Substances or the proceeds from a sale thereof, may claim to own a Working Interest or Royalty Interest in and to any Tract or in the Unitized Substances allocated thereto, shall be deemed to have warranted its title to such interest, and, upon receipt of the Unitized Substances or the proceeds from a sale thereof to the credit of such interest, shall indemnify and hold harmless all other Persons in interest from any loss due to failure, in whole or in part, of its title to any such interest.

**Production Where Title is in Dispute**. If the title or right of any Person claiming the right to receive in kind all or any portion of the Unitized Substances allocated to a Tract is in dispute, Unit Operator at the direction of Working Interest Owners may: Require that the Person to whom such Unitized Substances are delivered or to whom the proceeds from a sale thereof are paid furnish security for the proper accounting therefor to the rightful owner or owners if the title or right of such Person fails in whole or in part; or withhold and market the portion of Unitized Substances with respect to which title or right is in dispute, and hold the proceeds thereof until such time as the title or right thereto is established by a final judgment of a court of competent jurisdiction or otherwise to the satisfaction of Working Interest Owners, whereupon the proceeds so held shall be paid to the Person rightfully entitled thereto.

**Transfer of Title.** Any conveyance of all or any part of any interest owned by any Person hereto with respect to any Tract shall be made expressly subject to this Agreement. No change of title shall be binding upon Unit Operator, or upon any Person hereto other than the Person so transferring, until 7:00 a.m. on the first day of the calendar month next succeeding the date of receipt by Unit Operator of a certified copy of the recorded instrument evidencing such change in ownership.

## ARTICLE 8: EASEMENTS, GRANTS, OR USE OF SURFACE

**Grant of Easements**. Subject to the terms and conditions of the various leases, Unit Operator shall have the right of ingress and egress along with the right to use as much of the surface of the land within the Unit Area as may be reasonably necessary for Unit Operations and the removal of Unitized Substances from the Unit Area.

**Use of Water**. Subject to the terms and conditions of the various leases, Unit Operator shall have and is hereby granted free use of water from the Unit Area for Unit Operations, except water from any well, lake, pond, or irrigation ditch of a Royalty Owner. Unit Operator may convert dry or abandoned wells in the Unit Area for use as water supply or disposal wells.

**Surface Damages**. Subject to the terms and conditions of the various leases, Working Interest Owners shall reimburse the owner for the market value prevailing in the area of growing crops, livestock, timber, fences, improvements, and structures on the Unit Area that are destroyed or damaged as a result of Unit Operations.

**Unitized Property**. Notwithstanding anything in this Article 8 to the contrary, and except where otherwise authorized by separate agreement or by the Division, there shall be no Unit Operations conducted on the surface of any property located within the Siberian Unit, and there shall be no right of ingress and egress over and no right to use the surface waters of any surface lands located within the Siberian Unit, owned by an interest owner identified in Exhibit 1-A.3.

## ARTICLE 9: CHANGE OF TITLE

**Covenant Running with the Land**. This Agreement shall extend to, be binding upon, and inure to the benefit of, the respective heirs, devisees, legal representatives, successors, and assigns of the parties hereto, and shall constitute a covenant running with the lands, leases, and interests conveyed hereby.

**Waiver of Rights of Partition**. Each party to this Agreement understands and acknowledges, and is hereby deemed to covenant and agree, that during the term of this Agreement it will not resort to any action to, and shall not, partition Oil and Gas Rights, the Unit Area, the Unitized Formation, the Unitized Substances or the Unit Equipment, and to that extent waives the benefits of all laws authorizing such partition.

## ARTICLE 10: RELATIONSHIPS OF PERSONS

**No Partnership**. All duties, obligations, and liabilities arising hereunder shall be several and not joint or collective. This Agreement is not intended to and shall not be construed to create an association or trust, or to impose a partnership or fiduciary duty, obligation, or liability. Each Person affected hereby shall be individually responsible for its own obligations.

**No Joint or Cooperative Refining, Sale or Marketing**. This Agreement is not intended and shall not be construed to provide, directly or indirectly, for any joint or cooperative refining, sale or marketing of Unitized Substances.

## ARTICLE 11: EFFECTIVE DATE

**Effective Date**. This Agreement shall become effective, and operations may commence hereunder, as of the date of an effective order approving this unit by the Division in accordance with the provisions of Ohio Revised Code Section 1509.28; provided, however, that Working Interest Owners may terminate this Agreement in the event of a material modification by the Division of all or any part of this Agreement in such order by filing a notice of termination with the Division within thirty (30) days of such order becoming final and no longer subject to further appeal. In the event a dispute arises or exists with respect to this Agreement or the order approving this unit issued by the Division, Unit Operator may, in its sole discretion, hold the revenues from the sale of Unitized Substances until such time as such dispute is resolved or, in the Unit Operator's opinion, it is appropriate to distribute such revenues.

## ARTICLE 12: TERM

**Term**. This Agreement, unless sooner terminated in the manner hereinafter provided, shall remain in effect for one (1) year from the Effective Date and as long thereafter as Unitized Substances are produced, or are capable of being produced, in paying quantities from the Unit Area without a cessation of more than one hundred eighty (180) consecutive days, or so long as other Unit Operations are conducted without a cessation of more than one hundred eighty (180) consecutive days, unless sooner terminated by Working Interest Owners owning a combined Unit Participation of fifty-one percent (51%) or more whenever such Working Interest Owners determine that Unit Operations are no longer warranted. The date of any termination hereunder shall be known as the "Termination Date."

**Effect of Termination**. Upon termination of this Agreement, the further development and operation of the Unitized Formation as a unit shall cease. Each oil and gas lease and other agreement covering lands within the Unit Area shall remain in force for 180 days after the date on which this Agreement terminates, and for such further period as is provided by the lease or other agreement. The relationships among owners of Oil and Gas Rights shall thereafter be governed by the terms and provisions of the leases and other instruments, not including this Agreement, affecting the separate Tracts.

**Certificate of Termination**. Upon termination of this Agreement, Unit Operator shall file with the Division and for record in the county or counties in which the land affected is located a certificate stating that this Agreement has terminated and the Termination Date.

**Salvaging Equipment Upon Termination**. If not otherwise granted by the leases or other instruments affecting the separate Tracts, Working Interest Owners shall have a period of six (6) months after the Termination Date within which to salvage and remove Unit Equipment.

## ARTICLE 13: APPROVAL

**Original, Counterpart, or Other Instrument**. An owner of Oil and Gas Rights or its agent may approve this Agreement by signing the original, a counterpart thereof, or other instrument approving this Agreement. The signing of any such instrument shall have the same effect as if all Persons had signed the same instrument.

**Commitment of Interests to Unit**. The approval of this Agreement by a Person or their agent shall bind that Person and commit all interests owned or controlled by that Person as of the date of such approval, and additional interests thereafter acquired.

**Joinder in Dual Capacity**. Execution as herein provided by any Person, as either Working Interest Owner or a Royalty Owner, shall commit all interests owned or controlled by such Person as of the date of such execution and any additional interest thereafter acquired.

## ARTICLE 14: MISCELLANEOUS

**Determinations by Working Interest Owners**. All decisions, determinations, or approvals by Working Interest Owners hereunder shall be made pursuant to the voting procedure of any Unit Operating Agreement governing the rights and obligations of Working Interest Owners unless otherwise provided herein.

**Severability of Provisions**. The provisions of this Agreement are severable and if any section, sentence, clause or part thereof is held to be invalid for any reason, such invalidity shall not be construed to affect the validity of the remaining provisions of this Agreement.

**Laws and Regulations.** This Agreement shall be governed by and subject to the laws of the State of Ohio, to the valid rules, regulations, orders and permits of the Division, and to all other applicable federal, state, and municipal laws, rules, regulations, orders, and ordinances. Any change of the Unit Area or any amendment to this Agreement shall be in accordance with Ohio law.

Submitted by:

Antero Resources Corporation

By: Sloane Ford

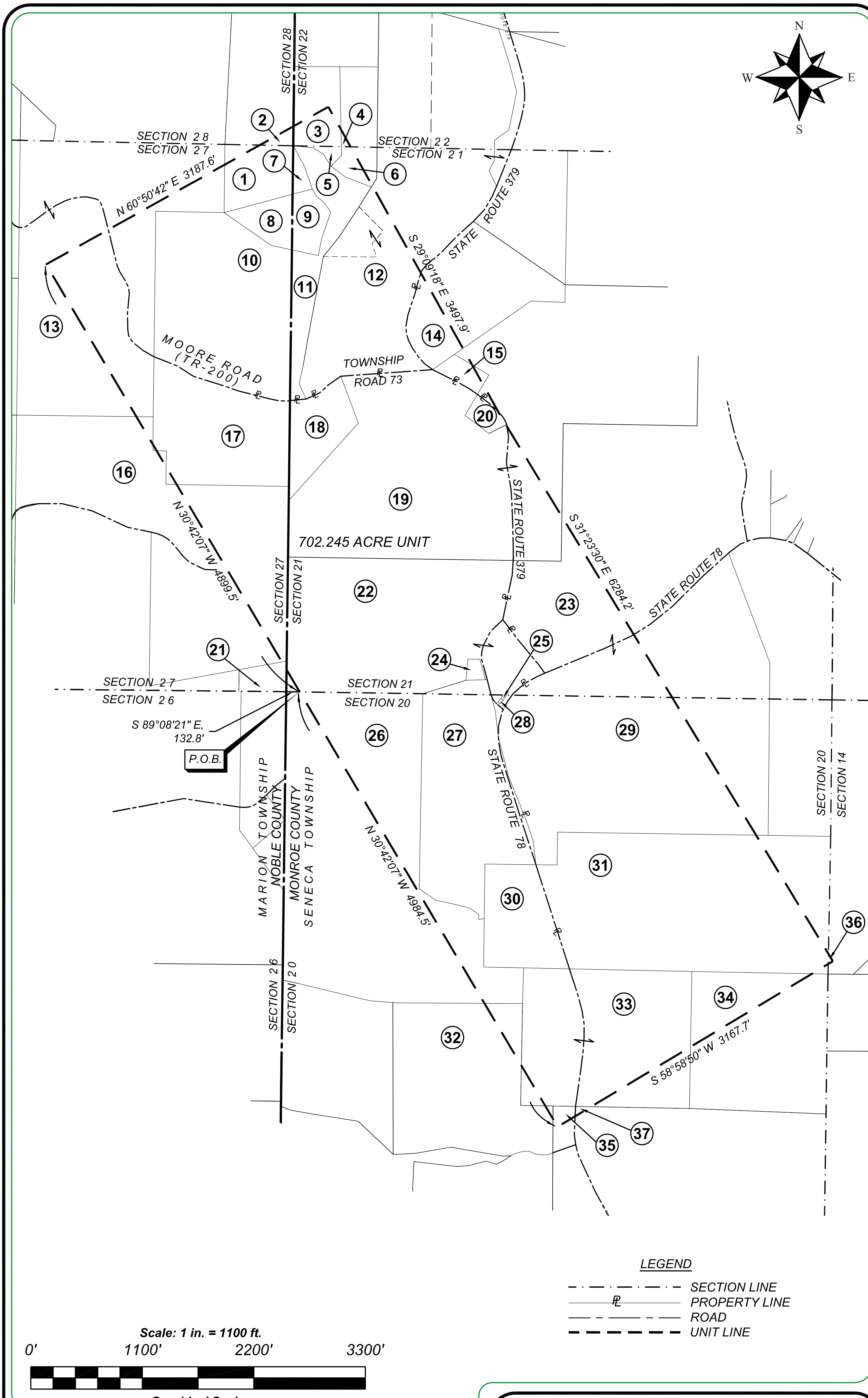
Sloane Ford
Landman
Antero Resources Corporation
1615 Wynkoop Street
Denver, Colorado 80202
Tel. (303) 357-6733
E-mail: sford@anteroresources.com

This instrument prepared by:

R. Neal Pierce (0028379)
Katerina E. Milenkovski (0063314)
Ryan S. Bundy (0090027)
STEPTOE & JOHNSON PLLC
Huntington Center
41 South High Street, Suite 2200
Columbus, Ohio 43215
Tel. (614) 221-5100
E-mail:neal.pierce@steptoe-johnson.com

All Tracts within Siberian Unit

| Tract | Owner | Address | Parcel Number | Deed Acreage | Unit Acreage | Unit Participation |
|---|---|---|---|---|---|---|
| 1 | The Pond Minerals, LLC | 28312 Township Road 73<br>Lewisville, OH 43754 | 23-21148.001 | 8.89600 | 8.099 | 1.15330% |
| 2 | Bowen Land Minerals, LLC | 28312 Township Road 73<br>Lewisville, OH 43754 | 23-21139.001 | 20.00000 | 0.217 | 0.03090% |
| 3 | The Pond Minerals, LLC | 28312 Township Road 73<br>Lewisville, OH 43754 | 20-10015.000 | 8.33700 | 2.394 | 0.34091% |
| 4 | The Pond Minerals, LLC | 28312 Township Road 73<br>Lewisville, OH 43754 | 20-10014.000 | 6.61000 | 0.174 | 0.02478% |
| 5 | The Pond Minerals, LLC | 28312 Township Road 73<br>Lewisville, OH 43754 | 20-17023.000 | 0.71900 | 0.716 | 0.10196% |
| 6 | The Pond Minerals, LLC | 28312 Township Road 73<br>Lewisville, OH 43754 | 20-17022.000 | 2.94300 | 0.930 | 0.13243% |
| 7 | The Pond Minerals, LLC | 28312 Township Road 73<br>Lewisville, OH 43754 | 20-17021.000 | 1.17100 | 1.167 | 0.16618% |
| 8 | The Pond Minerals, LLC | 28312 Township Road 73<br>Lewisville, OH 43754 | 23-21148.002 | 4.76300 | 4.766 | 0.67868% |
| 9 | The Pond Minerals, LLC | 28312 Township Road 73<br>Lewisville, OH 43754 | 20-17024.000 | 4.28500 | 4.281 | 0.60962% |
| 10 | The Pond Minerals, LLC<br>Gary and Nancy Rubel | 28312 Township Road 73<br>Lewisville, OH 43754<br>37779 SR 78<br>Woodsfield, OH 43793 | 23-21148.000 | 48.76500 | 48.768 | 6.94458% |
| 11 | The Pond Minerals, LLC | 28312 Township Road 73<br>Lewisville, OH 43754 | 20-17018.000 | 13.39800 | 13.397 | 1.90774% |
| 12 | Gary A. and Nancy S. Rubel | 37779 SR 78<br>Woodsfield, OH 43793 | 20-17004.000 | 60.02800 | 34.080 | 4.85301% |
| 13 | Antero Resources Corporation | 1615 Wynkoop Street<br>Denver, CO 80202 | 23-21143.000 | 93.97800 | 33.114 | 4.71545% |
| 14 | Gary and Nancy Rubel | 37779 SR 78<br>Woodsfield, OH 43793 | 20-17019.000 | 27.20400 | 5.662 | 0.80627% |
| 15 | Bryon D. and Joann Carpenter;<br>Brandon and Kimberly Ward | 49542 SR 379<br>Lewisville, OH 43754 | 20-17017.000 | 2.28400 | 2.028 | 0.28879% |
| 16 | Michael and Patricia R. Campbell | 626 E. Cross St.<br>Summerfield, OH 43788 | 23-51118.000 | 88.63400 | 23.619 | 3.36336% |
| 17 | Gary A. and Nancy S. Rubel | 37779 SR 78<br>Woodsfield, OH 43793 | 23-21144.000 | 30.05000 | 29.816 | 4.24581% |
| 18 | Gary A. and Nancy S. Rubel | 37779 SR 78<br>Woodsfield, OH 43793 | 20-17025.000 | 10.30400 | 10.350 | 1.47384% |
| 19 | Wallace R. and Judy A. Carpenter | 49415 State Route 379<br>Lewisville, OH 43754 | 20-17003.000 | 137.34000 | 83.419 | 11.87890% |
| 20 | Tammy M. Guy FKA Tammy M. Yocum | 49449 SR 379<br>Lewisville, OH 43754 | 20-17016.000 | 1.87600 | 1.776 | 0.25290% |
| 21 | Gary A. and Nancy S. Rubel | 37779 SR 78<br>Woodsfield, OH 43793 | 23-21156.000 | 2.71000 | 0.045 | 0.00641% |
| 22 | Carson D. and Teresa L. Spence | 15896 CR 13<br>Caldwell, OH 43724 | 20-17003.100 | 63.75000 | 66.702 | 9.49839% |
| 23 | Ruby H. Heft | 28924 SR 78<br>Lewisville, OH 43754 | 20-17007.000 | 154.13000 | 35.358 | 5.03499% |
| 24 | Martha L. Cline | 49055 Township Highway 27<br>Lewisville, OH 43754 | 20-17011.000 | 0.75000 | 0.733 | 0.10438% |
| 25 | State of Ohio - John Maynard | 1980 West Broad Street<br>Columbus , OH 43223 | 20-18012.100 | 0.03100 | 0.034 | 0.00484% |
| 26 | Gary and Nancy Rubel | 37779 SR 78<br>Woodsfield, OH 43793 | 21-18017.000 | 108.48600 | 36.937 | 5.25985% |
| 27 | Carson D. and Teresa L. Spence | 15896 CR 13<br>Caldwell, OH 43724 | 20-18001.000 | 41.18000 | 41.835 | 5.95732% |
| 28 | State of Ohio - John Maynard | 1980 West Broad Street<br>Columbus , OH 43223 | 21-18012.000 | 0.02000 | 0.030 | 0.00427% |
| 29 | Ruby H. Heft | 28924 SR 78<br>Lewisville, OH 43754 | 20-18011.000 | 69.84000 | 64.003 | 9.11406% |
| 30 | Crist R. and Amanda L. Byler | 28586 State Route 78<br>Lewisville, OH 43754 | 21-18006.000 | 10.57800 | 15.762 | 2.24452% |
| 31 | Steven R. McClain | 7119 Akron Ave.<br>Canal Fulton, OH 44614 | 21-18014.000 | 84.17200 | 74.354 | 10.58804% |
| 32 | Amy M. Zwick | 28452 TR 76<br>Lewisville, OH 43754 | 21-18008.000 | 40.00000 | 2.751 | 0.39174% |
| 33 | Charles F. Yontz | 28611 Twp. Hwy. 245<br>Summerfield, OH 43788 | 21-18004.000 | 48.25000 | 43.821 | 6.24013% |
| 34 | Charles F. Yontz | 28611 Twp. Hwy. 245<br>Summerfield, OH 43788 | 20-18002.000 | 40.00000 | 10.104 | 1.43881% |
| 35 | Amy M. Zwick | 28452 Twp. Hwy. 76<br>Lewisville, OH 43754 | 21-18016.000 | 2.09200 | 0.777 | 0.11065% |
| 36 | Charles F. Yontz<br>Charles E. Yontz<br>Wayne F. Yontz<br>Paul V. Yontz | 28611 Twp. Hwy. 245<br>Summerfield, OH 43788 | 20-19006.000 | 95.82000 | 0.053 | 0.00755% |
| 37 | Rockhill Acres, LLC | 28343 SR 78<br>Lewisville, OH 43754 | 21-18013.00 | 70.84100 | 0.173 | 0.02464% |
| | | | | **TOTAL** | **702.24500** | **100.00000%** |




| | | | |
|---|---|---|---|
| ISSUE DATE | 08/19/14 | SCALE | 1" = 1000' |
| DRAWN BY | LDB | DATE | 08/12/14 |
| CHECKED BY | JH | DATE | 08/19/14 |
| APPROVED BY | TRA | DATE | 08/19/14 |


Diversified Engineering Inc.
CONSULTING ENGINEERS & SURVEYORS
225 FAIR AVENUE, N.E
NEW PHILADELPHIA, OH 44663
Phone: (330) 364-1631
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e-mail: dei@diveng.com
Web: www.diveng.com


**OPERATOR: ANTERO RESOURCES CORPORATION**
**1615 WYNKOOP STREET**
**DENVER, CO 80202**

# SIBERIAN UNIT

LOCATION: SECTIONS 14, 20, 21, 22, 27 & 28 OF TOWNSHIP 7 NORTH, RANGE 7 WEST, OLD SEVEN RANGES, MARION & SENECA TOWNSHIPS NOBLE & MONROE COUNTY, OHIO

\\CTERANAS\Public\Alpha-Data\Data\OIL & GAS\Antero\Wilson Pad\PLAT\SIBERIAN UNIT DOU (08-12-2014).dwg , 8/19/2014 11:24 AM

Exhibit 1-A.3

Unleased Tracts in Siberian Unit

| Tract | Owner | Parcel | Unit Acreage | Unit Participation |
|---|---|---|---|---|
| 25 | State of Ohio - John Maynard | 20-18012.100 | 0.034 | 0.00484% |
| 28 | State of Ohio - John Maynard | 21-18012.000 | 0.030 | 0.00427% |
| | | **TOTAL** | **0.064** | |

**Oil and Gas Lease**

**THIS OIL AND GAS LEASE** (hereinafter, "**Lease**") made and entered into on this _____day of _____________**, 2014,** by and between ______________________________**,** whose address is ________________________________ (hereinafter, "**Lessor**") (collectively if there is more than one) and **ANTERO RESOURCES CORPORATION**, whose address is 1625 17th Street, Denver, Colorado 80202 (hereinafter, "**Lessee**").

## GRANT OF LEASE

1) That the Lessor, for and in consideration of paid-up annual rentals commonly known as a signing cash bonus of _____ ($______) for each net mineral acre covered by this Lease, paid by the Lessee (the "Bonus"), and of the royalties as provided, the covenants and agreements contained herein does hereby exclusively grant, convey, lease and let unto the Lessee, all of the oil, gas, liquid and gaseous hydrocarbons and their constituents and by-products thereof from formations below the base of the ______ formation at a depth of approximately _____feet, as seen in the _____________Well (API Number _______________) located in Section ___, _____Township, ______County, Ohio, to a depth of __________feet (_____') below the base of the ________________, in and under the Leased Premises, for the exclusive right to drill, explore, conduct seismic prospect, operate for, produce, remove and market oil, gas, hydrocarbons and their constituents and by-products therefrom, and to otherwise conduct all such secondary, enhanced, or tertiary operations as may be required in the opinion of the Lessee and the right to transport, use and maintain, by pipelines or otherwise across and through said lands, oil, gas and their constituents and products thereof, including water, brine or any other fluid or substances, only from the below defined Leased Premises and from other lands unitized or pooled therewith, and the right to enter thereon at all times and to occupy and use so much of the leased Premises as is necessary or convenient for only the aforesaid purposes. Lessee shall always act as a reasonable prudent operator exercising good faith in all of its activities with the Lessor. The above grant excludes any right to store gas, or inject any fluids or brine of any kind into the Leased Premises for any purpose of storage or disposal. **Notwithstanding anything in this Lease to the contrary, this Lease shall be considered a non-surface use Lease, such that the same is given for the purpose allowing Lessee to explore for, drill for, develop, produce, measure, and market production of oil and gas and their constituents from the Leased Premises by use of the surface of lands that are adjacent, adjoining or are pooled or unitized with the Leased Premises, provided that, Lessee shall not drill any wells, set surface equipment, install any pipe conduit or other appurtenance, enter upon or use the surface of the Leased Premises for any purpose whatsoever without first obtaining prior written consent of Lessor, which consent may be approved or denied for any reason.**

## DESCRIPTION OF THE LAND INCLUDED IN THIS LEASE

2) The land included in this Lease, herein called the "Leased Premises" is identified as follows:

| County | Township | Sec/Twp/Range | Acreage | Tax Number | Prior Deed Reference |
|---|---|---|---|---|---|
| | | | | | |
| | | | | | |

## OIL AND GAS ONLY

3) This Lease covers only Oil and Gas produced through a well bore. Thus, this Lease does not include and there is hereby excepted and reserved unto Lessor all the sulfur, coal, lignite, uranium and other fissionable material, geothermal energy, base and precious metals, rock, stone, gravel, and any other mineral substances (excepting those described above) presently owned by Lessor in, under, or upon the Leased Premises, together with right of ingress and egress and use of the Leased Premises by Lessor or its lessees or assignees for the purpose of exploration for and production and marketing of materials

Exhibit 1-B

and minerals reserved hereby; provided, however, Lessor's right to develop the reserved minerals shall not interfere with the rights herein granted to Lessee.

**NO STORAGE RIGHTS**

4) Notwithstanding anything herein contained to the contrary, Lessee agrees the herein described Leased Premises shall not be used for the purpose of gas storage.

**NO DELAY RENTAL**

5) Lessor shall not receive any paid annual rentals since this is a paid-up in advance Lease.

**TERMS**

6)

A) This Lease shall continue in force and the rights granted hereunder shall be quietly enjoyed by the Lessee during the primary term of five (5) years from the Effective Date of the Lease ("Primary Term") and so long thereafter as Oil and Gas are produced on the Leased Premises or land contiguously pooled or unitized herewith, in paying quantities or for as long as Lessee is conducting Operations to explore, develop, and produce Oil and Gas.

B) If Lessee drills a well which is incapable of producing in paying quantities (hereinafter called "dry hole") on the Leased Premises or lands pooled or unitized therewith, or if all production (whether or not in paying quantities) permanently ceases from any cause, including a revision of Unit boundaries pursuant to the provisions of this lease or the action of any governmental authority, then in the event this lease is not otherwise being maintained in force it shall nevertheless remain in force if Lessee commences further Operations for reworking an existing well, drilling an additional well or, otherwise obtaining or restoring production on the Leased Premises or lands pooled or unitized therewith within 180 days after completion of Operations on such dry hole or within 180 days after such cessation of all production. If after the primary term this lease is not otherwise being maintained in force, but Lessee is then engaged in Operations, as defined below, then this lease shall remain in force so long as any one or more Operations are prosecuted with no interruption of more than 180 consecutive days. If any such Operations result in the production of Oil and Gas, this lease will remain in force for as long thereafter as there is production in paying quantities from the Leased Premises or lands pooled or unitized therewith.

**ROYALTY AND GAS MEASUREMENT**

7) As royalties, Lessee covenants and agrees:

A) Oil. Lessee shall pay Lessor ____ Percent (___%) of the gross proceeds of all oil, other liquid hydrocarbons and by-products produced from or on the Leasehold Estate and sold by Lessee in an arms' length transaction and less the same proportionate share of all production, petroleum excise and severance taxes. In the event that Lessee sells all or part of the oil and other liquid hydrocarbons produced from the Leasehold Estate to an Affiliated Entity, the value thereof shall be the highest price offered to Lessee through Lessee's bidding process for the sale of such oil less the same proportionate share of all production, petroleum excise and severance taxes.

B) Gas. Lessee shall pay Lessor _____Percent (___%) of the gross proceeds received by Lessee for all gas and other hydrocarbons and by-products produced from or on the Leasehold Estate and sold by Lessee in an arms length transaction of or through an Affiliated Entity on the sales or re-sales of such gas, the value thereof shall be the higher of (a) the sales price received by Lessee, or (b) the sale price received on all of the Affiliated Entity's sales of the aggregated production volumes, where such aggregated production volumes include production from the Leasehold Estate during applicable months of sales less the same proportionate share of all production, petroleum excise and severance taxes.

C) Market Enhancement Clause. It is agreed between the Lessor and Lessee that, notwithstanding any language herein to the contrary, all royalties for oil, gas or other production (including but not limited to natural gas liquids and/or condensate, such as ethane, propane and butane) accruing to the Lessor under this Lease shall be paid without deduction, directly or indirectly, for the costs or expenses of Lessee (or an Affiliate of Lessee) relating to producing, gathering, storing, separating, treating, dehydrating, compressing, processing, transporting, and marketing the oil, gas and other products produced hereunder; *provided, however*, Lessee may deduct from Lessor's royalties accruing under the Lease, Lessor's proportionate share of any cost or expense actually incurred and charged to Lessee by a third party that is not owned or controlled by Lessee and relating thereto on the express condition such costs or expenses are necessarily incurred to enhance the value of the oil, gas or other products, including transforming product into a marketable form, and in any such case, the computation of the Lessor's royalty shall include the additional consideration, if any, paid to Lessee as a result of any enhancement of the market value of such products.

D) When Royalties Must Be Paid: All royalties that may become due hereunder shall commence to be paid on the first well completed on the Leased Premises within one hundred-eighty (180) days after the first day of the month following the month during which any well is completed and commences production into a pipeline for sale of such production. On each subsequent well, royalty payments must commence within one hundred-twenty (120) days after the first day of the month following the month during which any well is completed and commences production into a pipeline for sale of such production. Thereafter, all royalties on oil shall be paid to the Lessor on or before the last day the second month following the month of production, and all royalties on gas shall be paid to Lessor on or before the last day of the third month following the month of production. Royalties not paid when due shall bear interest at the prime rate, plus five percent (5%) per annum. Lessee may withhold royalties without obligation to pay interest in the event of a *bona fide* dispute or a good faith question of royalty entitlement (either as to ownership or as to amount).

**LESSOR'S INTEREST**

8) Notwithstanding any other actual or constructive knowledge or notice thereof to Lessee, it successors or assigns, no change or division in the ownership of the Leased Premises or the royalties or other monies, or the right to receive the same, howsoever affected, shall be binding upon the then record owner of this Lease until thirty (30) days after there has been furnished to such record owner at his or its principal place of business by Lessor or Lessor's heirs, successors, or assigns, notice by certified mail of such change or division, supported by either originals or copies of the instruments which have been properly filed for record and which evidences such change or division, and of such court records and proceedings, transcript, or other documents as shall be necessary in the opinion of such record owner to establish the validity of such change or division. If any such change in ownership occurs by reason of the death of the Lessor, Lessee may nevertheless pay or tender such royalties or other moneys, or part thereof, to Lessor. Lessee shall not be bound by any change of the address of Lessor until furnished by certified mail with such documentation from Lessor as Lessee may reasonably require.

**DEFINITIONS**

9)

A) Division Order. Documents setting forth the proportional ownership of Lessor in Lease products.

B) Effective Date and Primary Term. This Lease shall become effective on the date of the Chief's Order authorizing operation of the ____ Unit.

C) Oil or Gas. The term "Oil" shall mean crude oil, condensate, and other liquid hydrocarbons separated from gas on the Leased Premises by a field-type separator or other comparable equipment. The term "Gas" shall mean all substances, whether similar or dissimilar, produced in a gaseous state, including without limitation, casinghead gas, coal bed methane gas (including coalbed gas, coal mine methane,

methane gas, occluded gas and other naturally occurring gases contained in or produced from any coal seam or formation), gob gas, helium, carbon dioxide, and gaseous sulfur compounds.

## AUDIT RIGHTS

10) Lessee further grants to Lessor or Lessor's designee the right, at Lessor's expense, to examine, audit, copy or inspect books, records and accounts of Lessee pertinent to the purpose of verifying the accuracy of the reports and statements furnished to the Lessor, and for checking the amount of payments lawfully due the Lessor under the terms of this agreement; however, such audit rights shall be limited to not more than one audit every twelve (12) months. In exercising this right, Lessor shall give reasonable notice to Lessee of its intended audit and such audit shall be conducted during normal business hours at the office of Lessee at the sole cost and expense of Lessor. In the event the audit reveals deficiencies in royalty payments that are in excess of ten percent (10%) of the total royalties paid to Lessor during the audit period, then Lessee shall bear the cost and expense of the audit, and all monies due shall be payable within thirty (30) days of the final determination of the amounts due, and that Lessor shall be allowed to perform, at Lessor's discretion, a follow-up audit within twelve months of the completion of the audit that revealed the excessive deficiencies.

## METHOD OF PAYMENTS

11) All rents and royalties (except payment by gas in kind at the election of Lessor as may be provided herein) and any and all sums due hereunder from Lessee to Lessor shall be paid by one of the following methods:

A) By check or draft tendered directly from Lessee to Lessor at Lessor's address as stated in this Lease.

B) By direct deposit, depositing the payment to the credit of the Lessor in the bank and account number as provided in writing by Lessor to Lessee prior to such payment (which bank shall continue as depository for all sums payable hereunder until any subsequent written notice otherwise is provided by Lessor to Lessee). Any payment not timely made or not made in the correct amount shall not constitute a waiver by Lessor of any rights or remedies of Lessor under this Lease. A payment submitted electronically shall be considered timely paid if such payment is successfully transmitted to Lessor's account on or before the due date. A payment not submitted electronically shall be considered timely paid if delivered to the Lessor on or before the applicable due date or if deposited in a postpaid, properly addressed wrapper with a post office or official depository marked as so deposited by the United States postal service before the applicable due date.

## EXISTING WELLS

12) Lessee shall give due regard to existing Oil and Gas wells, the wells operations, tanks, lines and equipment on the Leased Premises, regardless of the drilling date, and Lessee, in conducting its Operations hereunder, shall take such commercially reasonable precautions necessary to protect the use and operation of the Oil and Gas wells by Lessor or other Lessees. Lessor reserves all rights to any production from any existing Oil and Gas well.

## COMMENCEMENT OF OPERATION

13) The term "Operations" as used in this Lease shall mean (a) the operations associated with producing Oil and Gas subsequent to drilling or (b) the constructing of a well site, drilling, fracturing, fracing, hydrofracing, completing, reworking, recompleting, deepening, plugging back or repairing of a well to obtain or re-establish production of Oil and Gas, conducted in good faith and with due diligence, whether on the Leased Premises or any lands unitized or contiguously pooled therewith. The term "Operations" shall not include conducting seismic or other similar testing, or the laying of pipeline across the Leased Premises. Commencement of Operations shall be defined as Lessee having secured a drilling permit from the State and further entering upon the Leased Premises or

any lands unitized or contiguously pooled therewith with equipment necessary to conduct one or more of the Operations.

**FORCE MAJEURE**

14) Should Lessee be prevented by reason of Force Majeure from complying with any express or implied covenant of this Lease (except payment of money), from conducting Operations at the Leased Premises or any lands unitized or contiguously pooled therewith, then while so prevented, (a) that covenant will be suspended; (b) Lessee will not be liable for damages for failure to comply therewith; (c) this Lease will be extended so long as Lessee is prevented from conducting such Operations under or from producing Oil and Gas from the Leased Premises; and (d) the time while Lessee is so prevented from complying will not be considered a breach of the applicable covenants of this Leases and any applicable time limitations shall be extended for the period of such Force Majeure. For purposes of this Lease, "Force Majeure" shall mean any cause that is not within the control of Lessee, and which, even with the exercise of reasonable due diligence, Lessee could not have prevented. Examples of Force Majeure include, without limitation: legal and lawful strikes, lockouts or other industrial disturbances; sabotage, wars, blockades, insurrections and riots; epidemics; landslides, lightning, earthquakes, fires, storms, warnings of imminent storms, floods, washouts and other events of nature or the elements (exclusive of normal weather patterns); restraints of governments and people and civil disturbances; and legislative, governmental or judicial actions that are resisted in good faith and temporary or permanent regulatory restraints or prohibitions applicable to the entire oil and gas industry in the area. This paragraph is, however, in all things subject to the limitations of time during which this Lease may be continued in force by the payment of shut-in royalties. Notwithstanding the foregoing, this period of extension by reason of a Force Majeure shall be limited to a cumulative total of three (3) years.

**POOLED PRODUCTION UNIT LIMITED**

15)

A) The production of Oil or Gas under the terms of this Lease will maintain this Lease beyond its primary term including any extensions thereto only as to that portion of the Leased Premises that is actually included within a Unit or Units that contains a well or wells then producing in paying quantities for so long as such well(s) are producing in paying quantities. A Unit shall mean a unit determined by a well spacing unit, a spacing order, or Order for Unit Operations, issued by ODNR's Mineral Resources Management (or other government entity with jurisdiction) for a particular well. In the absence of such order from the ODNR's Mineral Resources Management (or other government entity with jurisdiction), Lessee shall designate and file a "well plat production unit", which for the purpose of this Lease, shall contain only the acreage overlaying that portion of the target formation or pool under a well that a prudent operator would deem capable of being most efficiently drained by that well while utilizing the best production technology in common use at the time of drilling. Notwithstanding any density rules applicable to any well, however, no production unit or pooled acreage assigned to any well shall exceed the following unit acreage sizes:

(i) If the well is classified as a vertical Oil or Gas well, the maximum size of the pooled production unit shall be 40 contiguous acres, without the written consent of Lessor. The well shall be located in the center of the production unit to the extent practical, and such unit shall be of a square or rectangular shape consistent with state regulations.

(ii) If the well is classified as a horizontal Oil or Gas well drilled to any geologic formations containing a horizontal component of the drain hole in the target formation, whether Oil or Gas, then the maximum size of the pooled production unit shall not exceed 1,000 contiguous acres, plus an acreage tolerance of 10% if the lateral extent of horizontal bore hole(s) in said formation shall extend beyond the boundary of a 1,000 contiguous acre unit and such that a reasonably prudent operator would expect that the entire acreage within such larger unit will be effectively and efficiently developed and drained from a central pad site location. The Unit shall, to the extent practical, parallel and be centered on the lateral boreholes to be drilled within the Unit, and such Unit shall be of a square or rectangular shape consistent with state regulations.

B) Any well drilled on said Unit whether or not the well(s) are located on the Leased Premises, shall, nevertheless be deemed to be located upon the Leased Premises within the meaning and for the provisions and covenants of this Lease to the same effect as if all the lands comprising said Unit were described in and subject to this Lease; and provided further that the Lessor agrees to accept that proportion of such royalties and shut-in payments, which the amount of Lessor's acreage placed in the unit or his/her/its royalty interests therein on the acreage basis, bears to the total acreage in the Unit. The Lessee shall effect such consolidation by executing a declaration of consolidation with the same formality as this Lease setting forth the lease or portions thereof consolidated and respective royalty distribution, and recording the same in the recorder's office at the courthouse in the county in which the Leased Premises are located and by mailing a copy thereof to the Lessor at the address hereinabove set forth unless the Lessee is furnished with another address. Lessee shall have the right to amend, alter, change, correct, or cancel any such consolidation Unit or amended consolidation Unit, in the sole opinion of the Lessee, the amended Unit would be beneficial in connection with the conservation and development of Oil and Gas, so long as such amendment satisfies the restrictions set forth above.

C) This Lease shall automatically terminate and be of no further force or effect as to any portion of the Leased Premises which is not included within a producing or drilling Unit at the expiration of the Primary Term, or any extension thereof, from which Oil and Gas are being produced in paying quantities from the geologic formations leased herein or Operations are being conducted in such Unit. Upon termination of this Lease, and Lessor's written request, as to any portion of the Leased Premises as provided in this paragraph, Lessee shall promptly deliver to Lessor a plat showing the designated Unit(s) around each well and a partial release containing a satisfactory description of the acreage not retained, suitable for recording.

**REASONABLE DEVELOPMENT**

16) If Oil and Gas is discovered on the Leased Premises, Lessee shall develop the Leased Premises as a reasonable and prudent operator and exercise due diligence in drilling such additional well or wells as may be necessary to fully develop the Leased Premises.

**SHUT-IN PAYMENT/LIMITATION**

17) In the event all wells drilled on the Leased Premises or on land pooled or unitized hereunder are shut-in because Lessee is unable to market the production therefrom, or should production in paying quantities cease from all such wells, or should the Lessee desire to shut-in all such producing wells, the Lessee agrees to pay the Lessor, commencing on the date six (6) months from the beginning of the period with no production being sold, or the cessation of production, or the shutting-in of each producing well, a shut-in payment in the amount of fifty dollars ($50.00) per acre every six (6) months until the earlier of: production is marketed and sold off the Leased Premises, or such wells are plugged and abandoned according to law, or six (6) months after making the fourth (4) shut-in payment. Notwithstanding the making of such shut-in payments, Lessee shall be and remain under the continuing obligation to (a) use all reasonable efforts to find a market for said Gas and/or Oil and to commence or resume marketing the same when a market is available, (b) reasonably develop the Leased Premises as provided in this Lease. Upon delivery of the shut-in payment as provided herein, the Lease will continue in force and effect while production is shut-in. It is understood and agreed that, in the sole discretion of the Lessor, this Lease may not be maintained in force for any continuous period of time longer than thirty (30) months, or a cumulative period of forty-eight (48) months after the expiration of the Primary Term hereof solely by the provision of this shut-in clause.

**WATER DAMAGE**

18) Lessee shall not be the cause of the diminution of the quality or quantity of Lessor's water supplies as set forth below (including but not limited to all supplies, wells, creeks,

streams, ponds, and springs) for domestic and livestock use to be measured by testing Lessor's water supplies: (a) prior to the commencement of drilling the first well upon the Leased Premises (or within a drilling unit in which the Leased Premises is located within two thousand five-hundred (2,500) feet of any well bore); (b) at the completion of the drilling and completion of all wells upon the Leased Premises (or within a drilling unit in which the Leased Premises is located within two thousand five-hundred (2,500) feet of any well bore); and, (c) as deemed necessary by Lessor due to changes in water flow or quality, including but not limited to color, smell or taste. Should any of Lessor's water supply(ies) located within 2,500 feet of any well bore be diminished in quality or diminished in volume so as to violate maximum allowable concentration levels for constituents pursuant to federal or state drinking/water quality standards or be insufficient in volume for domestic household and/or livestock use as set forth below, Lessee shall take steps to restore water quality and quantity to its pre-existing condition (remediation) at Lessee's cost and fully compensate Lessor for the damage caused thereby; provided, that initial baseline water quality data did not already show the existence of the constituent(s) above maximum allowable concentration levels for the constituent(s) pursuant to federal or state drinking/water quality standards and there is evidence of a clear diminution of volume of water produced by the water supply(ies) not attributable to natural fluctuations in quantity. Remediation of water quality shall be considered complete when testing shows the concentration(s) of the constituent(s) are at or below federal or state maximum allowable concentration levels. During the period of remediation, Lessee shall supply Lessor with an adequate supply of potable water at Lessee's cost consistent with Lessor's use of the damaged water supply prior to Lessee's Operation. Any diminution in the quality or quantity of the above described water supply(ies) , unless shown to have occurred more than 6 months after the drilling and completion of all wells upon the Leased Premises (or within a drilling unit in which the Leased Premises is located within two thousand five-hundred (2,500) feet an any well bore, will be presumed to be the result of Lessee's Operations unless Lessee can prove otherwise, with Lessee having the burden of proof by the preponderance of the evidence. Until Lessee can prove otherwise as to cause, Lessee shall provide the required replacement supply; beginning immediately upon Lessor's providing evidence to Lessee of the water quality and quantity condition causing concern. Testing of Lessor's water supply(ies) as set forth above shall be at Lessee's cost, and shall be conducted by an independent testing laboratory certified by the Ohio Environmental Protection Agency and/or the Ohio Department of Health. Lessor's water supply(ies) shall be tested for the parameters included on the attached water quality parameters list. Lessor shall be provided complete copies of any and all testing results and data and shall have full rights to contact the testing lab for inquiry and information.

**NO USE OF WATER**

19) Lessee shall not use water from Lessor's surface, subsurface, wells, ponds, lakes, springs, creeks or reservoirs ("Water") located on the Leased Premises without first obtaining the prior written consent of Lessor. Lessor and Lessee contemplate negotiations and agreement for the cost for onsite water usage but neither party is bound to offer to pay, or accept said offer, for any reason. Lessee shall be fully responsible for any material damage caused to Lessor's Water by any operations conducted pursuant to this Lease.

**HUNTER**

20) Lessee agrees that its employees, agents, subcontractors, and independent contractors shall have no right to and are prohibited from firing any firearms, hunting or fishing, on the Leased Premises, without the written permission of the Lessor.

**INSURANCE/HOLD HARMLESS**

21)

A) Insurance: A company licensed by the Ohio Department of Commerce-Division of Insurance to do business within the State of Ohio shall underwrite all policies required by this paragraph. Provided, however, such insurance requirements maybe met by a combination of self-insurance, primary and excess insurance Policies. Lessee shall carry the following insurance with one or more insurance carriers at any and all times such party or person is on or about the Leased Premises or acting pursuant to this Lease in such amounts as from time to time reasonably required by Lessor. Lessee shall endeavor to assure that any person acting on Lessee's behalf under this lease shall carry substantially similar insurance:

i. Workers' Compensation and Employer's Liability Insurance

ii. Commercial General Liability and Umbrella Liability Insurance ($5,000,000.00 Minimum Coverage) which shall include liability coverage for sudden and accidental pollution incidents;

iii. Business auto and Umbrella Liability Insurance ($5,000,000.00 Minimum Coverage).

Upon Lessor's request, the Lessee shall cause Certificates of Insurance evidencing the above coverage to be provided promptly upon request to Lessor.

B) Indemnity: Lessee and its successors and assigns, shall defend, indemnify, release and hold harmless Lessor and Lessor's heirs, successors, representatives, agents and assigns ("Indemnitees"), from and against any and all claims, liabilities, judgments, fines, penalties, interests, demands and causes of action for injury (including death) or damages and losses to persons or property, including attorneys' fees and court costs, arising out of, incidental to or resulting from the operations conducted on the Leased Premises or caused by operations of the Lessee or Lessee's servants, agents, employees, guests, licensees, invitees or independent contractors, and each assignee of this Lease, or an interest holder therein, agrees to indemnify and hold harmless Indemnitees in the same manner provided above. Each assignee of the Lessee, or any interest therein, agrees to indemnify and hold harmless to the Indemnitees as if said assignee were party to this Lease when executed. The provisions of this paragraph shall survive the termination of this Lease.

**SUBORDINATION**

22) Lessee agrees and acknowledges that any unsubordinated pre-existing mortgage on the Leased Premises that covers Lessor's oil and gas rights may constitute a title defect, except to the extent cured by Ohio Codified Laws and if there does exist said title defect and the well or well bore is on or directly under the Leased Premises, or any lands unitized or contiguously pooled therewith, the title defect must be cured at Lessor's expense by Lessor obtaining a subordination of that mortgage.

**BINDING ON SUCCESSORS AND ASSIGNS**

23) This Lease and all of its terms, conditions, covenants and stipulations shall extend to and be binding on all heirs, personal representatives, successors and assigns of Lessor and Lessee.

**ADDITIONAL DOCUMENTS**

24) Lessor further agrees to sign such additional documents as may be reasonably requested by Lessee to perfect Lessee's title to the Oil and Gas leased herein, as described in paragraph 1, and such other documents relating to the sale of production as may be required by Lessee or others. Said obligation includes but is not limited to modifying or amending any legal descriptions to release acreage which does not have marketable title or correcting any inaccurate legal descriptions.

**FUTURE MORTGAGES AND ENCUMBRANCES**

25) Lessor may at any time, without providing notice to Lessee, mortgage Lessor's interest in all or any part of the Leased Premises, or grant any easement or other servitude, including but not limited to other leases, as Lessor deems necessary and appropriate, and which do not interfere with Lessee's rights herein.

**CONDEMNATION**

26) Any and all payments made by a Condemner on account of taking by eminent domain

shall be the property of the Lessor, except a taking or diminishment of Lessee's interest in either the rights and privileges granted in the leasehold estate created hereby or the oil and gas reserves located within the Leased Premises, and in the event of such a taking or diminishment of Lessee's interests and/or rights, Lessee shall be entitled to its proportionate share of any payments, and shall further have a right of standing in any proceeding of Condemnation.

## PARTIAL RELEASE

27) Lessee shall have the right at any time during this Lease to release from the lands covered hereby any lands subject to this Lease and thereby may be relieved of all obligations hereafter accruing to the acreage so released, provided that (a) Lessee may not release any portion of this Lease included in a pooled Unit so long as Operations are being conducted on such Unit, and (b) any such partial release must release all depths in and under the lands so released.

## TERMINATION OF RECORD AND MEMORANDUM OF LEASE

28)

A) Upon termination of the Lease as to any portion of the Leased Premises, and Lessor's written request, Lessee shall promptly deliver to Lessor a release of the Lease. In addition, Lessee shall peaceably surrender the Leased Premises to Lessor and remove any and all facilities, equipments and machinery from the site within ninety (90) days at Lessee's expense. Further, the affected land shall be reclaimed in accordance with the terms of this Lease.

B) This Lease shall not be recorded by either party hereto. Lessor and Lessee shall execute a Memorandum of Lease for recording which shall set forth the names and addresses of the parties hereto, the description of the Leased Premises, the term of this Lease and the rest of the provisions hereof shall be incorporated by reference. Lessee shall be entitled to immediately record the Memorandum of Lease in the applicable county records. If Lessee determines to its reasonable satisfaction after its title due diligence review that the Lessor does not have marketable title to the Leased Premises, or if Lessee does not pay the Bonus payment in full prior to the Payment Date for any reason, and upon Lessor's written request, then Lessee shall promptly release any recorded Memorandum of Lease it may have filed and this Lease shall terminate.

## DEFAULT

29)

A) In addition to any incidents of default described throughout this Lease, the occurrence of any of the following constitutes a default hereunder:

   i. If any creditor of Lessee and/or assigns shall take any action to execute on, garnish, or attach the assets of the Lessee covering the Leased Premises, or

   ii. If a request or a petition for liquidation, reorganization, adjustment of debts, arrangement, or similar relief under the bankruptcy, insolvency or similar laws of the United States or any state or territory thereof or any foreign jurisdiction shall be filed by or against Lessee or any formal or informal proceeding for the reorganization, dissolution or liquidation of settlement of claims against, or winding up of affairs of the Lessee; or the garnishment, attachment, or taking by governmental authority of all of Lessee's collateral or other property.

B) Upon default by Lessee, Lessor shall be entitled to exercise any and all remedies available at law, in equity or otherwise, each such remedy being considered cumulative. No single exercise of any remedy set forth herein shall be deemed an election to forego any other remedy and any failure to pursue a remedy shall not prevent, restrict or otherwise modify its exercise subsequently.

## SEVERABILITY

30) If any provision of this Lease is held invalid or unenforceable by any court of competent

jurisdiction, the other provisions of this Lease will remain in full force and effect. Any provision of this Lease held invalid or unenforceable only in part or degree will remain in full force and effect to the extent not held invalid or unenforceable.

**GOVERNING LAW**

31) This Lease shall be governed and construed in accordance with the laws of the State of Ohio. Any and all disputes must be resolved, in a common pleas court located solely in the State of Ohio, and shall not be resolved by arbitration.

**LESSER INTEREST**

32) In case the Lessor owns a lesser interest in the Leased Premises than the entire or undivided fee simple interest therein, then the royalties, delay rentals and other payments herein provided for shall be paid to the Lessor in the proportion which such interest bears to the whole or undivided fee.

**REPORTS AND DOCUMENTS**

33) As required by law, Lessee shall notify Lessor of any judicial proceedings brought to the attention of Lessee affecting its possession under the Lease or the interest of Lessor in the Leased Premises.

**AUTHORSHIP AND WAIVER**

34) For the purpose of construction, interpretation and/or adjudication, it shall be deemed that Lessee and Lessor contributed equally to the drafting of this instrument. The failure of either party to enforce or exercise any provision of this Lease shall not constitute or be considered as a waiver of the provision in the future unless the same is expressed in writing and signed by the respective parties.

**DOWER**

35) In consideration of the execution of this Lease, Lessor hereby releases and relinquishes all Lessor's rights and expectancies of dower in the Lease.

**ASSIGNMENT**

36) Lessee, and any successor Lessee, shall have the right to assign and transfer the within Lease, in whole or in part.

**NOTICE**

37) If at any time after the execution of the Lease, it shall become necessary or convenient for one of the parties to serve any notice, demand or communication upon the other party, such notice, demand or communication shall be in writing signed by the party serving notice, sent by nationally recognized overnight carrier or registered or certified United States mail, return receipt requested and postage or other charges prepaid. Any such notice if intended for Lessor shall be addressed to the address set forth in the first paragraph of this Lease, and if intended for Lessee, the notice shall be addressed to the address set forth in the first paragraph of this Lease, or to such other address as either party may have furnished to the other in writing as a place for the service of notice. Any notice so sent shall be deemed to have been given/served as of the time it is deposited with the overnight carrier or in the United States mail.

**IN WITNESS WHEREOF**, the Lessor(s) hereunto set their hand(s) on the day and year first above written.

LESSOR(S)

____________________________________

By:

________________________________________
By:

# ACKNOWLEDGMENT

STATE OF OHIO )
COUNTY OF ___________ )

On the _______ day of ________________, 2014, before me, the undersigned officer, personally appeared

_____________________________________________, known to me or satisfactorily proven to be the person(s) whose name(s) is/are subscribed to the within instrument, and acknowledged that he/she/they executed the same for the purposes therein contained.

In witness whereof, I hereunto set my hand and official seal.

________________________________________
Notary Public

# Exhibit " C "
# ACCOUNTING PROCEDURE
# JOINT OPERATIONS

Attached to and made part of that certain Joint Operating Agreement dated March 28, 2014 by and between Antero Resources Corporation as Operator and as Non-Operator.

## I. GENERAL PROVISIONS

**IF THE PARTIES FAIL TO SELECT EITHER ONE OF COMPETING "ALTERNATIVE" PROVISIONS, OR SELECT ALL THE COMPETING "ALTERNATIVE" PROVISIONS, ALTERNATIVE 1 IN EACH SUCH INSTANCE SHALL BE DEEMED TO HAVE BEEN ADOPTED BY THE PARTIES AS A RESULT OF ANY SUCH OMISSION OR DUPLICATE NOTATION.**

**IN THE EVENT THAT ANY "OPTIONAL" PROVISION OF THIS ACCOUNTING PROCEDURE IS NOT ADOPTED BY THE PARTIES TO THE AGREEMENT BY A TYPED, PRINTED OR HANDWRITTEN INDICATION, SUCH PROVISION SHALL NOT FORM A PART OF THIS ACCOUNTING PROCEDURE, AND NO INFERENCE SHALL BE MADE CONCERNING THE INTENT OF THE PARTIES IN SUCH EVENT.**

### 1. DEFINITIONS

All terms used in this Accounting Procedure shall have the following meaning, unless otherwise expressly defined in the Agreement:

**"Affiliate"** means for a person, another person that controls, is controlled by, or is under common control with that person. In this definition, (a) control means the ownership by one person, directly or indirectly, of more than fifty percent (50%) of the voting securities of a corporation or, for other persons, the equivalent ownership interest (such as partnership interests), and (b) "person" means an individual, corporation, partnership, trust, estate, unincorporated organization, association, or other legal entity.

**"Agreement"** means the operating agreement, farmout agreement, or other contract between the Parties to which this Accounting Procedure is attached.

**"Controllable Material"** means Material that, at the time of acquisition or disposition by the Joint Account, as applicable, is so classified in the Material Classification Manual most recently recommended by the Council of Petroleum Accountants Societies (COPAS).

**"Equalized Freight"** means the procedure of charging transportation cost to the Joint Account based upon the distance from the nearest Railway Receiving Point to the property.

**"Excluded Amount"** means a specified excluded trucking amount most recently recommended by COPAS.

**"Field Office"** means a structure, or portion of a structure, whether a temporary or permanent installation, the primary function of which is to directly serve daily operation and maintenance activities of the Joint Property and which serves as a staging area for directly chargeable field personnel.

**"First Level Supervision"** means those employees whose primary function in Joint Operations is the direct oversight of the Operator's field employees and/or contract labor directly employed On-site in a field operating capacity. First Level Supervision functions may include, but are not limited to:

- Responsibility for field employees and contract labor engaged in activities that can include field operations, maintenance, construction, well remedial work, equipment movement and drilling
- Responsibility for day-to-day direct oversight of rig operations
- Responsibility for day-to-day direct oversight of construction operations
- Coordination of job priorities and approval of work procedures
- Responsibility for optimal resource utilization (equipment, Materials, personnel)
- Responsibility for meeting production and field operating expense targets
- Representation of the Parties in local matters involving community, vendors, regulatory agents and landowners, as an incidental part of the supervisor's operating responsibilities
- Responsibility for all emergency responses with field staff
- Responsibility for implementing safety and environmental practices
- Responsibility for field adherence to company policy
- Responsibility for employment decisions and performance appraisals for field personnel
- Oversight of sub-groups for field functions such as electrical, safety, environmental, telecommunications, which may have group or team leaders.

**"Joint Account"** means the account showing the charges paid and credits received in the conduct of the Joint Operations that are to be shared by the Parties, but does not include proceeds attributable to hydrocarbons and by-products produced under the Agreement.

**"Joint Operations"** means all operations necessary or proper for the exploration, appraisal, development, production, protection, maintenance, repair, abandonment, and restoration of the Joint Property.

**"Joint Property"** means the real and personal property subject to the Agreement.

**"Laws"** means any laws, rules, regulations, decrees, and orders of the United States of America or any state thereof and all other governmental bodies, agencies, and other authorities having jurisdiction over or affecting the provisions contained in or the transactions contemplated by the Agreement or the Parties and their operations, whether such laws now exist or are hereafter amended, enacted, promulgated or issued.

**"Material"** means personal property, equipment, supplies, or consumables acquired or held for use by the Joint Property.

**"Non-Operators"** means the Parties to the Agreement other than the Operator.

**"Offshore Facilities"** means platforms, surface and subsea development and production systems, and other support systems such as oil and gas handling facilities, living quarters, offices, shops, cranes, electrical supply equipment and systems, fuel and water storage and piping, heliport, marine docking installations, communication facilities, navigation aids, and other similar facilities necessary in the conduct of offshore operations, all of which are located offshore.

**"Off-site"** means any location that is not considered On-site as defined in this Accounting Procedure.

**"On-site"** means on the Joint Property when in direct conduct of Joint Operations. The term "On-site" shall also include that portion of Offshore Facilities, Shore Base Facilities, fabrication yards, and staging areas from which Joint Operations are conducted, or other facilities that directly control equipment on the Joint Property, regardless of whether such facilities are owned by the Joint Account.

**"Operator"** means the Party designated pursuant to the Agreement to conduct the Joint Operations.

**"Parties"** means legal entities signatory to the Agreement or their successors and assigns. Parties shall be referred to individually as "Party."

**"Participating Interest"** means the percentage of the costs and risks of conducting an operation under the Agreement that a Party agrees, or is otherwise obligated, to pay and bear.

**"Participating Party"** means a Party that approves a proposed operation or otherwise agrees, or becomes liable, to pay and bear a share of the costs and risks of conducting an operation under the Agreement.

**"Personal Expenses"** means reimbursed costs for travel and temporary living expenses.

**"Railway Receiving Point"** means the railhead nearest the Joint Property for which freight rates are published, even though an actual railhead may not exist.

**"Shore Base Facilities"** means onshore support facilities that during Joint Operations provide such services to the Joint Property as a receiving and transshipment point for Materials; debarkation point for drilling and production personnel and services; communication, scheduling and dispatching center; and other associated functions serving the Joint Property.

**"Supply Store"** means a recognized source or common stock point for a given Material item.

**"Technical Services"** means services providing specific engineering, geoscience, or other professional skills, such as those performed by engineers, geologists, geophysicists, and technicians, required to handle specific operating conditions and problems for the benefit of Joint Operations; provided, however, Technical Services shall not include those functions specifically identified as overhead under the second paragraph of the introduction of Section III (*Overhead*). Technical Services may be provided by the Operator, Operator's Affiliate, Non-Operator, Non-Operator Affiliates, and/or third parties.

## 2. STATEMENTS AND BILLINGS

The Operator shall bill Non-Operators on or before the last day of the month for their proportionate share of the Joint Account for the preceding month. Such bills shall be accompanied by statements that identify the AFE (authority for expenditure), lease or facility, and all charges and credits summarized by appropriate categories of investment and expense. Controllable Material shall be separately identified and fully described in detail, or at the Operator's option, Controllable Material may be summarized by major Material classifications. Intangible drilling costs, audit adjustments, and unusual charges and credits shall be separately and clearly identified.

The Operator may make available to Non-Operators any statements and bills required under Section I.2 and/or Section I.3.A (*Advances and Payments by the Parties*) via email, electronic data interchange, internet websites or other equivalent electronic media in lieu of paper copies. The Operator shall provide the Non-Operators instructions and any necessary information to access and receive the statements and bills within the timeframes specified herein. A statement or billing shall be deemed as delivered twenty-four (24) hours (exclusive of weekends and holidays) after the Operator notifies the Non-Operator that the statement or billing is available on the website and/or sent via email or electronic data interchange transmission. Each Non-Operator individually shall elect to receive statements and billings electronically, if available from the Operator, or request paper copies. Such election may be changed upon thirty (30) days prior written notice to the Operator.

**3. ADVANCES AND PAYMENTS BY THE PARTIES**

A.

B. Except as provided below, each Party shall pay its proportionate share of all bills in full within fifteen (15) days of receipt date. If payment is not made within such time, the unpaid balance shall bear interest compounded monthly at the prime rate published by the *Wall Street Journal* on the first day of each month the payment is delinquent, plus three percent (3%), per annum, or the maximum contract rate permitted by the applicable usury Laws governing the Joint Property, whichever is the lesser, plus attorney's fees, court costs, and other costs in connection with the collection of unpaid amounts. If the *Wall Street Journal* ceases to be published or discontinues publishing a prime rate, the unpaid balance shall bear interest compounded monthly at the prime rate published by the Federal Reserve plus three percent (3%), per annum. Interest shall begin accruing on the first day of the month in which the payment was due. Payment shall not be reduced or delayed as a result of inquiries or anticipated credits unless the Operator has agreed. Notwithstanding the foregoing, the Non-Operator may reduce payment, provided it furnishes documentation and explanation to the Operator at the time payment is made, to the extent such reduction is caused by:

(1) being billed at an incorrect working interest or Participating Interest that is higher than such Non-Operator's actual working interest or Participating Interest, as applicable; or
(2) being billed for a project or AFE requiring approval of the Parties under the Agreement that the Non-Operator has not approved or is not otherwise obligated to pay under the Agreement; or
(3) being billed for a property in which the Non-Operator no longer owns a working interest, provided the Non-Operator has furnished the Operator a copy of the recorded assignment or letter in-lieu. Notwithstanding the foregoing, the Non-Operator shall remain responsible for paying bills attributable to the interest it sold or transferred for any bills rendered during the thirty (30) day period following the Operator's receipt of such written notice; or
(4) charges outside the adjustment period, as provided in Section I.4 (*Adjustments*).

**4. ADJUSTMENTS**

A. Payment of any such bills shall not prejudice the right of any Party to protest or question the correctness thereof; however, all bills and statements, including payout statements, rendered during any calendar year shall conclusively be presumed to be true and correct, with respect only to expenditures, after twenty-four (24) months following the end of any such calendar year, unless within said period a Party takes specific detailed written exception thereto making a claim for adjustment. The Operator shall provide a response to all written exceptions, whether or not contained in an audit report, within the time periods prescribed in Section I.5 (*Expenditure Audits*).

B. All adjustments initiated by the Operator, except those described in items (1) through (4) of this Section I.4.B, are limited to the twenty-four (24) month period following the end of the calendar year in which the original charge appeared or should have appeared on the Operator's Joint Account statement or payout statement. Adjustments that may be made beyond the twenty-four (24) month period are limited to adjustments resulting from the following:

(1) a physical inventory of Controllable Material as provided for in Section V (*Inventories of Controllable Material*), or
(2) an offsetting entry (whether in whole or in part) that is the direct result of a specific joint interest audit exception granted by the Operator relating to another property, or
(3) a government/regulatory audit, or
(4) a working interest ownership or Participating Interest adjustment.

**5. EXPENDITURE AUDITS**

A. A Non-Operator, upon written notice to the Operator and all other Non-Operators, shall have the right to audit the Operator's accounts and records relating to the Joint Account within the twenty-four (24) month period following the end of such calendar year in which such bill was rendered; however, conducting an audit shall not extend the time for the taking of written exception to and the adjustment of accounts as provided for in Section I.4 (*Adjustments*). Any Party that is subject to payout accounting under the Agreement shall have the right to audit the accounts and records of the Party responsible for preparing the payout statements, or of the Party furnishing information to the Party responsible for preparing payout statements. Audits of payout accounts may include the volumes of hydrocarbons produced and saved and proceeds received for such hydrocarbons as they pertain to payout accounting required under the Agreement. Unless otherwise provided in the Agreement, audits of a payout account shall be conducted within the twenty-four (24) month period following the end of the calendar year in which the payout statement was rendered.

Where there are two or more Non-Operators, the Non-Operators shall make every reasonable effort to conduct a joint audit in a manner that will result in a minimum of inconvenience to the Operator. The Operator shall bear no portion of the Non-Operators' audit cost incurred under this paragraph unless agreed to by the Operator. The audits shall not be conducted more than once each year without prior approval of the Operator, except upon the resignation or removal of the Operator, and shall be made at the expense of those Non-Operators approving such audit.

The Non-Operator leading the audit (hereinafter "lead audit company") shall issue the audit report within ninety (90) days after completion of the audit testing and analysis; however, the ninety (90) day time period shall not extend the twenty-four (24) month requirement for taking specific detailed written exception as required in Section I.4.A (*Adjustments*) above. All claims shall be supported with sufficient documentation.

A timely filed written exception or audit report containing written exceptions (hereinafter "written exceptions") shall, with respect to the claims made therein, preclude the Operator from asserting a statute of limitations defense against such claims, and the Operator hereby waives its right to assert any statute of limitations defense against such claims for so long as any Non-Operator continues to comply with the deadlines for resolving exceptions provided in this Accounting Procedure. If the Non-Operators fail to comply with the additional deadlines in Section I.5.B or I.5.C, the Operator's waiver of its rights to assert a statute of limitations defense against the claims brought by the Non-Operators shall lapse, and such claims shall then be subject to the applicable statute of limitations, provided that such waiver shall not lapse in the event that the Operator has failed to comply with the deadlines in Section I.5.B or I.5.C.

B. The Operator shall provide a written response to all exceptions in an audit report within one hundred eighty (180) days after Operator receives such report. Denied exceptions should be accompanied by a substantive response. If the Operator fails to provide substantive response to an exception within this one hundred eighty (180) day period, the Operator will owe interest on that exception or portion thereof, if ultimately granted, from the date it received the audit report. Interest shall be calculated using the rate set forth in Section I.3.B (*Advances and Payments by the Parties*).

C. The lead audit company shall reply to the Operator's response to an audit report within ninety (90) days of receipt, and the Operator shall reply to the lead audit company's follow-up response within ninety (90) days of receipt; provided, however, each Non-Operator shall have the right to represent itself if it disagrees with the lead audit company's position or believes the lead audit company is not adequately fulfilling its duties. Unless otherwise provided for in Section I.5.E, if the Operator fails to provide substantive response to an exception within this ninety (90) day period, the Operator will owe interest on that exception or portion thereof, if ultimately granted, from the date it received the audit report. Interest shall be calculated using the rate set forth in Section I.3.B (*Advances and Payments by the Parties*).

D. If any Party fails to meet the deadlines in Sections I.5.B or I.5.C or if any audit issues are outstanding fifteen (15) months after Operator receives the audit report, the Operator or any Non-Operator participating in the audit has the right to call a resolution meeting, as set forth in this Section I.5.D or it may invoke the dispute resolution procedures included in the Agreement, if applicable. The meeting will require one month's written notice to the Operator and all Non-Operators participating in the audit. The meeting shall be held at the Operator's office or mutually agreed location, and shall be attended by representatives of the Parties with authority to resolve such outstanding issues. Any Party who fails to attend the resolution meeting shall be bound by any resolution reached at the meeting. The lead audit company will make good faith efforts to coordinate the response and positions of the Non-Operator participants throughout the resolution process; however, each Non-Operator shall have the right to represent itself. Attendees will make good faith efforts to resolve outstanding issues, and each Party will be required to present substantive information supporting its position. A resolution meeting may be held as often as agreed to by the Parties. Issues unresolved at one meeting may be discussed at subsequent meetings until each such issue is resolved.

If the Agreement contains no dispute resolution procedures and the audit issues cannot be resolved by negotiation, the dispute shall be submitted to mediation. In such event, promptly following one Party's written request for mediation, the Parties to the dispute shall choose a mutually acceptable mediator and share the costs of mediation services equally. The Parties shall each have present at the mediation at least one individual who has the authority to settle the dispute. The Parties shall make reasonable efforts to ensure that the mediation commences within sixty (60) days of the date of the mediation request. Notwithstanding the above, any Party may file a lawsuit or complaint (1) if the Parties are unable after reasonable efforts, to commence mediation within sixty (60) days of the date of the mediation request, (2) for statute of limitations reasons, or (3) to seek a preliminary injunction or other provisional judicial relief, if in its sole judgment an injunction or other provisional relief is necessary to avoid irreparable damage or to preserve the status quo. Despite such action, the Parties shall continue to try to resolve the dispute by mediation.

***E.*** ☐ ***(Optional Provision – Forfeiture Penalties)***
~~*If the Non-Operators fail to meet the deadline in Section I.5.C, any unresolved exceptions that were not addressed by the Non-Operators within one (1) year following receipt of the last substantive response of the Operator shall be deemed to have been withdrawn by the Non-Operators. If the Operator fails to meet the deadlines in Section I.5.B or I.5.C, any unresolved exceptions that were not addressed by the Operator within one (1) year following receipt of the audit report or receipt of the last substantive response of the Non-Operators, whichever is later, shall be deemed to have been granted by the Operator and adjustments shall be made, without interest, to the Joint Account.*~~

## 6. APPROVAL BY PARTIES

### A. GENERAL MATTERS

Where an approval or other agreement of the Parties or Non-Operators is expressly required under other Sections of this Accounting Procedure and if the Agreement to which this Accounting Procedure is attached contains no contrary provisions in regard thereto, the

Operator shall notify all Non-Operators of the Operator's proposal and the agreement or approval of a majority in interest of the Non-Operators shall be controlling on all Non-Operators.

This Section I.6.A applies to specific situations of limited duration where a Party proposes to change the accounting for charges from that prescribed in this Accounting Procedure. This provision does not apply to amendments to this Accounting Procedure, which are covered by Section I.6.B.

B. AMENDMENTS

If the Agreement to which this Accounting Procedure is attached contains no contrary provisions in regard thereto, this Accounting Procedure can be amended by an affirmative vote of ________two________ (___2___) or more Parties, one of which is the Operator, having a combined working interest of at least _____ninety______ percent (__90__%), which approval shall be binding on all Parties, provided, however, approval of at least one (1) Non-Operator shall be required.

C. AFFILIATES

For the purpose of administering the voting procedures of Sections I.6.A and I.6.B, if Parties to this Agreement are Affiliates of each other, then such Affiliates shall be combined and treated as a single Party having the combined working interest or Participating Interest of such Affiliates.

For the purposes of administering the voting procedures in Section I.6.A, if a Non-Operator is an Affiliate of the Operator, votes under Section I.6.A shall require the majority in interest of the Non-Operator(s) after excluding the interest of the Operator's Affiliate.

## II. DIRECT CHARGES

The Operator shall charge the Joint Account with the following items:

### 1. RENTALS AND ROYALTIES

Lease rentals and royalties paid by the Operator, on behalf of all Parties, for the Joint Operations.

### 2. LABOR

A. Salaries and wages, ~~including incentive compensation programs as set forth in COPAS MFI-37 ("Chargeability of Incentive Compensation Programs"),~~ for:

(1) Operator's field employees directly employed On-site in the conduct of Joint Operations,

(2) Operator's employees directly employed on Shore Base Facilities, Offshore Facilities, or other facilities serving the Joint Property if such costs are not charged under Section II.6 (*Equipment and Facilities Furnished by Operator*) or are not a function covered under Section III (*Overhead*),

(3) Operator's employees providing First Level Supervision,

(4) Operator's employees providing On-site Technical Services for the Joint Property if such charges are excluded from the overhead rates in Section III (*Overhead*),

(5) Operator's employees providing Off-site Technical Services for the Joint Property if such charges are excluded from the overhead rates in Section III (*Overhead*).

Charges for the Operator's employees identified in Section II.2.A may be made based on the employee's actual salaries and wages, or in lieu thereof, a day rate representing the Operator's average salaries and wages of the employee's specific job category.

Charges for personnel chargeable under this Section II.2.A who are foreign nationals shall not exceed comparable compensation paid to an equivalent U.S. employee pursuant to this Section II.2, unless otherwise approved by the Parties pursuant to Section I.6.A (*General Matters*).

B. ~~Operator's cost of holiday, vacation, sickness, and disability benefits, and other customary allowances paid to employees whose salaries and wages are chargeable to the Joint Account under Section II.2.A, excluding severance payments or other termination allowances. Such costs under this Section II.2.B may be charged on a "when and as-paid basis" or by "percentage assessment" on the amount of salaries and wages chargeable to the Joint Account under Section II.2.A. If percentage assessment is used, the rate shall be based on the Operator's cost experience.~~

C. Expenditures or contributions made pursuant to assessments imposed by governmental authority that are applicable to costs chargeable to the Joint Account under Sections II.2.A and B.

D. Personal Expenses of personnel whose salaries and wages are chargeable to the Joint Account under Section II.2.A when the expenses are incurred in connection with directly chargeable activities.

E. ~~Reasonable relocation costs incurred in transferring to the Joint Property personnel whose salaries and wages are chargeable to the Joint Account under Section II.2.A. Notwithstanding the foregoing, relocation costs that result from reorganization or merger of a Party, or that are for the primary benefit of the Operator, shall not be chargeable to the Joint Account. Extraordinary relocation costs, such as those incurred as a result of transfers from remote locations, such as Alaska or overseas, shall not be charged to the Joint Account unless approved by the Parties pursuant to Section I.6.A (*General Matters*).~~

F. ~~Training costs as specified in COPAS MFI-35 ("Charging of Training Costs to the Joint Account") for personnel whose salaries and wages are chargeable under Section II.2.A. This training charge shall include the wages, salaries, training course cost, and Personal Expenses incurred during the training session. The training cost shall be charged or allocated to the property or properties directly benefiting from the training. The cost of the training course shall not exceed prevailing commercial rates, where such rates are available~~.

G. ~~Operator's current cost of established plans for employee benefits, as described in COPAS MFI-27 ("Employee Benefits Chargeable to Joint Operations and Subject to Percentage Limitation"), applicable to the Operator's labor costs chargeable to the Joint Account under Sections II.2.A and B based on the Operator's actual cost not to exceed the employee benefits limitation percentage most recently recommended by COPAS.~~

H. ~~Award payments to employees, in accordance with COPAS MFI-49 ("Awards to Employees and Contractors") for personnel whose salaries and wages are chargeable under Section II.2.A~~.

**3. MATERIAL**

Material purchased or furnished by the Operator for use on the Joint Property in the conduct of Joint Operations as provided under Section IV (Material *Purchases, Transfers, and Dispositions*). Only such Material shall be purchased for or transferred to the Joint Property as may be required for immediate use or is reasonably practical and consistent with efficient and economical operations. The accumulation of surplus stocks shall be avoided.

**4. TRANSPORTATION**

A. Transportation of the Operator's, Operator's Affiliate's, or contractor's personnel necessary for Joint Operations.

B. Transportation of Material between the Joint Property and another property, or from the Operator's warehouse or other storage point to the Joint Property, shall be charged to the receiving property using one of the methods listed below. Transportation of Material from the Joint Property to the Operator's warehouse or other storage point shall be paid for by the Joint Property using one of the methods listed below:

(1) If the actual trucking charge is less than or equal to the Excluded Amount the Operator may charge actual trucking cost or a theoretical charge from the Railway Receiving Point to the Joint Property. The basis for the theoretical charge is the per hundred weight charge plus fuel surcharges from the Railway Receiving Point to the Joint Property. The Operator shall consistently apply the selected alternative.

(2) If the actual trucking charge is greater than the Excluded Amount, the Operator shall charge Equalized Freight. Accessorial charges such as loading and unloading costs, split pick-up costs, detention, call out charges, and permit fees shall be charged directly to the Joint Property and shall not be included when calculating the Equalized Freight.

**5. SERVICES**

The cost of contract services, equipment, and utilities used in the conduct of Joint Operations, except for contract services, equipment, and utilities covered by Section III (*Overhead*), or Section II.7 (*Affiliates*), or excluded under Section II.9 (*Legal Expense*). Awards paid to contractors shall be chargeable pursuant to COPAS MFI-49 ("Awards to Employees and Contractors").

The costs of third party Technical Services are chargeable to the extent excluded from the overhead rates under Section III (*Overhead*).

**6. EQUIPMENT AND FACILITIES FURNISHED BY OPERATOR**

In the absence of a separately negotiated agreement, equipment and facilities furnished by the Operator will be charged as follows:

A.

B. the Operator may elect to use average commercial rates prevailing in the immediate area of the Joint Property. If equipment and facilities are charged under this Section II.6.B, the Operator shall adequately document and support commercial rates and shall periodically review and update the rate and the supporting documentation. For automotive equipment, the Operator may elect to use rates published by the Petroleum Motor Transport Association (PMTA) or such other organization recognized by COPAS as the official source of rates.

**7. AFFILIATES**




Exhibit 1-C

A. Charges for an Affiliate's goods and/or services used in operations requiring an AFE or other authorization from the Non-Operators may be made without the approval of the Parties provided (i) the Affiliate is identified and the Affiliate goods and services are specifically detailed in the approved AFE or other authorization, and (ii) the total costs for such Affiliate's goods and services billed to such individual project do not exceed $ 5,000.00 If the total costs for an Affiliate's goods and services charged to such individual project are not specifically detailed in the approved AFE or authorization or exceed such amount, charges for such Affiliate shall require approval of the Parties, pursuant to Section I.6.A (*General Matters*).

B. For an Affiliate's goods and/or services used in operations not requiring an AFE or other authorization from the Non-Operators, charges for such Affiliate's goods and services shall require approval of the Parties, pursuant to Section I.6.A (*General Matters*), if the charges exceed $ 5,000.00 in a given calendar year.

C. The cost of the Affiliate's goods or services shall not exceed average commercial rates prevailing in the area of the Joint Property, unless the Operator obtains the Non-Operators' approval of such rates. The Operator shall adequately document and support commercial rates and shall periodically review and update the rate and the supporting documentation; provided, however, documentation of commercial rates shall not be required if the Operator obtains Non-Operator approval of its Affiliate's rates or charges prior to billing Non-Operators for such Affiliate's goods and services. Notwithstanding the foregoing, direct charges for Affiliate-owned communication facilities or systems shall be made pursuant to Section II.12 (*Communications*).

If the Parties fail to designate an amount in Sections II.7.A or II.7.B, in each instance the amount deemed adopted by the Parties as a result of such omission shall be the amount established as the Operator's expenditure limitation in the Agreement. If the Agreement does not contain an Operator's expenditure limitation, the amount deemed adopted by the Parties as a result of such omission shall be zero dollars ($ 0.00).

## 8. DAMAGES AND LOSSES TO JOINT PROPERTY

All costs or expenses necessary for the repair or replacement of Joint Property resulting from damages or losses incurred, except to the extent such damages or losses result from a Party's or Parties' gross negligence or willful misconduct, in which case such Party or Parties shall be solely liable.

The Operator shall furnish the Non-Operator written notice of damages or losses incurred as soon as practicable after a report has been received by the Operator.

## 9. LEGAL EXPENSE

Recording fees and costs of handling, settling, or otherwise discharging litigation, claims, and liens incurred in or resulting from operations under the Agreement, or necessary to protect or recover the Joint Property, to the extent permitted under the Agreement. Costs of the Operator's or Affiliate's legal staff or outside attorneys, including fees and expenses, are not chargeable unless approved by the Parties pursuant to Section I.6.A (*General Matters*) or otherwise provided for in the Agreement.

Notwithstanding the foregoing paragraph, costs for procuring abstracts, fees paid to outside attorneys for title examinations (including preliminary, supplemental, shut-in royalty opinions, division order title opinions), and curative work shall be chargeable to the extent permitted as a direct charge in the Agreement.

## 10. TAXES AND PERMITS

All taxes and permitting fees of every kind and nature, assessed or levied upon or in connection with the Joint Property, or the production therefrom, and which have been paid by the Operator for the benefit of the Parties, including penalties and interest, except to the extent the penalties and interest result from the Operator's gross negligence or willful misconduct.

If ad valorem taxes paid by the Operator are based in whole or in part upon separate valuations of each Party's working interest, then notwithstanding any contrary provisions, the charges to the Parties will be made in accordance with the tax value generated by each Party's working interest.

Costs of tax consultants or advisors, the Operator's employees, or Operator's Affiliate employees in matters regarding ad valorem or other tax matters, are not permitted as direct charges unless approved by the Parties pursuant to Section I.6.A (*General Matters*).

Charges to the Joint Account resulting from sales/use tax audits, including extrapolated amounts and penalties and interest, are permitted, provided the Non-Operator shall be allowed to review the invoices and other underlying source documents which served as the basis for tax charges and to determine that the correct amount of taxes were charged to the Joint Account. If the Non-Operator is not permitted to review such documentation, the sales/use tax amount shall not be directly charged unless the Operator can conclusively document the amount owed by the Joint Account.

**11. INSURANCE**

Net premiums paid for insurance required to be carried for Joint Operations for the protection of the Parties. If Joint Operations are conducted at locations where the Operator acts as self-insurer in regard to its worker's compensation and employer's liability insurance obligation, the Operator shall charge the Joint Account manual rates for the risk assumed in its self-insurance program as regulated by the jurisdiction governing the Joint Property. In the case of offshore operations in federal waters, the manual rates of the adjacent state shall be used for personnel performing work On-site, and such rates shall be adjusted for offshore operations by the U.S. Longshoreman and Harbor Workers (USL&H) or Jones Act surcharge, as appropriate.

**12. COMMUNICATIONS**

~~Costs of acquiring, leasing, installing, operating, repairing, and maintaining communication facilities or systems, including satellite, radio and microwave facilities, between the Joint Property and the Operator's office(s) directly responsible for field operations in accordance with the provisions of COPAS MFI-44 ("Field Computer and Communication Systems"). If the communications facilities or systems serving the Joint Property are Operator-owned, charges to the Joint Account shall be made as provided in Section II.6 (*Equipment and Facilities Furnished by Operator*). If the communication facilities or systems serving the Joint Property are owned by the Operator's Affiliate, charges to the Joint Account shall not exceed average commercial rates prevailing in the area of the Joint Property. The Operator shall adequately document and support commercial rates and shall periodically review and update the rate and the supporting documentation~~.

**13. ECOLOGICAL, ENVIRONMENTAL, AND SAFETY**

Costs incurred for Technical Services and drafting to comply with ecological, environmental and safety Laws or standards recommended by Occupational Safety and Health Administration (OSHA) or other regulatory authorities. All other labor and functions incurred for ecological, environmental and safety matters, including management, administration, and permitting, shall be covered by Sections II.2 (*Labor*), II.5 (*Services*), or Section III (*Overhead*), as applicable.

Costs to provide or have available pollution containment and removal equipment plus actual costs of control and cleanup and resulting responsibilities of oil and other spills as well as discharges from permitted outfalls as required by applicable Laws, or other pollution containment and removal equipment deemed appropriate by the Operator for prudent operations, are directly chargeable.

**14. ABANDONMENT AND RECLAMATION**

Costs incurred for abandonment and reclamation of the Joint Property, including costs required by lease agreements or by Laws.

**15. OTHER EXPENDITURES**

Any other expenditure not covered or dealt with in the foregoing provisions of this Section II (*Direct Charges*), or in Section III (*Overhead*) and which is of direct benefit to the Joint Property and is incurred by the Operator in the necessary and proper conduct of the Joint Operations. Charges made under this Section II.15 shall require approval of the Parties, pursuant to Section I.6.A (*General Matters*).

## III. OVERHEAD

As compensation for costs not specifically identified as chargeable to the Joint Account pursuant to Section II (*Direct Charges*), the Operator shall charge the Joint Account in accordance with this Section III.

Functions included in the overhead rates regardless of whether performed by the Operator, Operator's Affiliates or third parties and regardless of location, shall include, but not be limited to, costs and expenses of:

- warehousing, other than for warehouses that are jointly owned under this Agreement
- design and drafting (except when allowed as a direct charge under Sections II.13, III.1.A(ii), and III.2, Option B)
- inventory costs not chargeable under Section V (*Inventories of Controllable Material*)
- procurement
- administration
- accounting and auditing
- gas dispatching and gas chart integration

- human resources
- management
- supervision not directly charged under Section II.2 (*Labor*)
- legal services not directly chargeable under Section II.9 (*Legal Expense*)
- taxation, other than those costs identified as directly chargeable under Section II.10 (*Taxes and Permits*)
- preparation and monitoring of permits and certifications; preparing regulatory reports; appearances before or meetings with governmental agencies or other authorities having jurisdiction over the Joint Property, other than On-site inspections; reviewing, interpreting, or submitting comments on or lobbying with respect to Laws or proposed Laws.

Overhead charges shall include the salaries or wages plus applicable payroll burdens, benefits, and Personal Expenses of personnel performing overhead functions, as well as office and other related expenses of overhead functions.

**1. OVERHEAD—DRILLING AND PRODUCING OPERATIONS**

As compensation for costs incurred but not chargeable under Section II (*Direct Charges*) and not covered by other provisions of this Section III, the Operator shall charge on either:

☑ **(Alternative 1)** Fixed Rate Basis, Section III.1.B.
☐ ~~**(Alternative 2)** Percentage Basis, Section III.1.C~~.

A. TECHNICAL SERVICES

(i) Except as otherwise provided in Section II.13 (*Ecological Environmental, and Safety*) and Section III.2 (*Overhead – Major Construction and Catastrophe*), or by approval of the Parties pursuant to Section I.6.A (*General Matters*), the salaries, wages, related payroll burdens and benefits, and Personal Expenses for **On-site** Technical Services, including third party Technical Services:

☑ **(Alternative 1 – Direct)** shall be charged **direct** to the Joint Account.

☐ ~~**(Alternative 2 – Overhead)** shall be covered by the **overhead** rates~~.

(ii) Except as otherwise provided in Section II.13 (*Ecological, Environmental, and Safety*) and Section III.2 (*Overhead – Major Construction and Catastrophe*), or by approval of the Parties pursuant to Section I.6.A (*General Matters*), the salaries, wages, related payroll burdens and benefits, and Personal Expenses for **Off-site** Technical Services, including third party Technical Services:

☑ **(Alternative 1 – All Overhead)** shall be covered by the **overhead** rates.

☐ ~~**(Alternative 2 – All Direct)** shall be charged **direct** to the Joint Account.~~

☐ ~~**(Alternative 3 – Drilling Direct)** shall be charged **direct** to the Joint Account, **only** to the extent such Technical Services are directly attributable to drilling, redrilling, deepening, or sidetracking operations, through completion, temporary abandonment, or abandonment if a dry hole. Off-site Technical Services for all other operations, including workover, recompletion, abandonment of producing wells, and the construction or expansion of fixed assets not covered by Section III.2 (*Overhead - Major Construction and Catastrophe*) shall be covered by the overhead rates~~.

Notwithstanding anything to the contrary in this Section III, Technical Services provided by Operator's Affiliates are subject to limitations set forth in Section II.7 (*Affiliates*). Charges for Technical personnel performing non-technical work shall not be governed by this Section III.1.A, but instead governed by other provisions of this Accounting Procedure relating to the type of work being performed.

B. OVERHEAD—FIXED RATE BASIS

(1) The Operator shall charge the Joint Account at the following rates per well per month:

Drilling Well Rate per month $ 6,000.00 (prorated for less than a full month)

Producing Well Rate per month $ 600.00

(2) Application of Overhead—Drilling Well Rate shall be as follows:

(a) Charges for onshore drilling wells shall begin on the spud date and terminate on the date the drilling and/or completion equipment used on the well is released, whichever occurs later. Charges for offshore and inland waters drilling wells shall begin on the date the drilling or completion equipment arrives on location and terminate on the date the drilling or completion equipment moves off location, or is released, whichever occurs first. No charge shall be made during suspension of drilling and/or completion operations for fifteen (15) or more consecutive calendar days.

(b) Charges for any well undergoing any type of workover, recompletion, and/or abandonment for a period of five (5) or more consecutive work–days shall be made at the Drilling Well Rate. Such charges shall be applied for the period from date operations, with rig or other units used in operations, commence through date of rig or other unit release, except that no charges shall be made during suspension of operations for fifteen (15) or more consecutive calendar days.

(3) Application of Overhead—Producing Well Rate shall be as follows:

(a) An active well that is produced, injected into for recovery or disposal, or used to obtain water supply to support operations for any portion of the month shall be considered as a one-well charge for the entire month.

(b) Each active completion in a multi-completed well shall be considered as a one-well charge provided each completion is considered a separate well by the governing regulatory authority.

(c) A one-well charge shall be made for the month in which plugging and abandonment operations are completed on any well, unless the Drilling Well Rate applies, as provided in Sections III.1.B.(2)(a) or (b). This one-well charge shall be made whether or not the well has produced.

(d) An active gas well shut in because of overproduction or failure of a purchaser, processor, or transporter to take production shall be considered as a one-well charge provided the gas well is directly connected to a permanent sales outlet.

(e) Any well not meeting the criteria set forth in Sections III.1.B.(3) (a), (b), (c), or (d) shall not qualify for a producing overhead charge.

(4) The well rates shall be adjusted on the first day of April each year following the effective date of the Agreement; provided, however, if this Accounting Procedure is attached to or otherwise governing the payout accounting under a farmout agreement, the rates shall be adjusted on the first day of April each year following the effective date of such farmout agreement. The adjustment shall be computed by applying the adjustment factor most recently published by COPAS. The adjusted rates shall be the initial or amended rates agreed to by the Parties increased or decreased by the adjustment factor described herein, for each year from the effective date of such rates, in accordance with COPAS MFI-47 (“Adjustment of Overhead Rates”).

**2. OVERHEAD—MAJOR CONSTRUCTION AND CATASTROPHE**

To compensate the Operator for overhead costs incurred in connection with a Major Construction project or Catastrophe, the Operator shall either negotiate a rate prior to the beginning of the project, or shall charge the Joint Account for overhead based on the following rates for any Major Construction project in excess of the Operator’s expenditure limit under the Agreement, or for any Catastrophe regardless of the amount. If the Agreement to which this Accounting Procedure is attached does not contain an expenditure limit, Major Construction Overhead shall be assessed for any single Major Construction project costing in excess of $100,000 gross.

Major Construction shall mean the construction and installation of fixed assets, the expansion of fixed assets, and any other project clearly discernible as a fixed asset required for the development and operation of the Joint Property, or in the dismantlement, abandonment, removal, and restoration of platforms, production equipment, and other operating facilities.

Catastrophe is defined as a sudden calamitous event bringing damage, loss, or destruction to property or the environment, such as an oil spill, blowout, explosion, fire, storm, hurricane, or other disaster. The overhead rate shall be applied to those costs necessary to restore the Joint Property to the equivalent condition that existed prior to the event.

A. If the Operator absorbs the engineering, design and drafting costs related to the project:

(1) 5.00 % of total costs if such costs are less than $100,000; plus

(2) 3.00 % of total costs in excess of $100,000 but less than $1,000,000; plus

(3) 2.00 % of total costs in excess of $1,000,000.

B. If the Operator charges engineering, design and drafting costs related to the project directly to the Joint Account:

(1) 0.00 % of total costs if such costs are less than $100,000; plus

(2) 0.00 % of total costs in excess of $100,000 but less than $1,000,000; plus

(3) 0.00 % of total costs in excess of $1,000,000.

Total cost shall mean the gross cost of any one project. For the purpose of this paragraph, the component parts of a single Major Construction project shall not be treated separately, and the cost of drilling and workover wells and purchasing and installing pumping units and downhole artificial lift equipment shall be excluded. For Catastrophes, the rates shall be applied to all costs associated with each single occurrence or event.

On each project, the Operator shall advise the Non-Operator(s) in advance which of the above options shall apply.

For the purposes of calculating Catastrophe Overhead, the cost of drilling relief wells, substitute wells, or conducting other well operations directly resulting from the catastrophic event shall be included. Expenditures to which these rates apply shall not be reduced by salvage or insurance recoveries. Expenditures that qualify for Major Construction or Catastrophe Overhead shall not qualify for overhead under any other overhead provisions.

In the event of any conflict between the provisions of this Section III.2 and the provisions of Sections II.2 (*Labor*), II.5 (*Services*), or II.7 (*Affiliates*), the provisions of this Section III.2 shall govern.

**3. AMENDMENT OF OVERHEAD RATES**

The overhead rates provided for in this Section III may be amended from time to time if, in practice, the rates are found to be insufficient or excessive, in accordance with the provisions of Section I.6.B (*Amendments*).

## IV. MATERIAL PURCHASES, TRANSFERS, AND DISPOSITIONS

The Operator is responsible for Joint Account Material and shall make proper and timely charges and credits for direct purchases, transfers, and dispositions. The Operator shall provide all Material for use in the conduct of Joint Operations; however, Material may be supplied by the Non-Operators, at the Operator's option. Material furnished by any Party shall be furnished without any express or implied warranties as to quality, fitness for use, or any other matter.

**1. DIRECT PURCHASES**

Direct purchases shall be charged to the Joint Account at the price paid by the Operator after deduction of all discounts received. The Operator shall make good faith efforts to take discounts offered by suppliers, but shall not be liable for failure to take discounts except to the extent such failure was the result of the Operator's gross negligence or willful misconduct. A direct purchase shall be deemed to occur when an agreement is made between an Operator and a third party for the acquisition of Material for a specific well site or location. Material provided by the Operator under "vendor stocking programs," where the initial use is for a Joint Property and title of the Material does not pass from the manufacturer, distributor, or agent until usage, is considered a direct purchase. If Material is found to be defective or is returned to the manufacturer, distributor, or agent for any other reason, credit shall be passed to the Joint Account within sixty (60) days after the Operator has received adjustment from the manufacturer, distributor, or agent.

**2. TRANSFERS**

A transfer is determined to occur when the Operator (i) furnishes Material from a storage facility or from another operated property, (ii) has assumed liability for the storage costs and changes in value, and (iii) has previously secured and held title to the transferred Material. Similarly, the removal of Material from the Joint Property to a storage facility or to another operated property is also considered a transfer; provided, however, Material that is moved from the Joint Property to a storage location for safe-keeping pending disposition may remain charged to the Joint Account and is not considered a transfer. Material shall be disposed of in accordance with Section IV.3 (*Disposition of Surplus*) and the Agreement to which this Accounting Procedure is attached.

A. PRICING

The value of Material transferred to/from the Joint Property should generally reflect the market value on the date of physical transfer. Regardless of the pricing method used, the Operator shall make available to the Non-Operators sufficient documentation to verify the Material valuation. When higher than specification grade or size tubulars are used in the conduct of Joint Operations, the Operator shall charge the Joint Account at the equivalent price for well design specification tubulars, unless such higher specification grade or sized tubulars are approved by the Parties pursuant to Section I.6.A (*General Matters*). Transfers of new Material will be priced using one of the following pricing methods; provided, however, the Operator shall use consistent pricing methods, and not alternate between methods for the purpose of choosing the method most favorable to the Operator for a specific transfer:

(1) Using published prices in effect on date of movement as adjusted by the appropriate COPAS Historical Price Multiplier (HPM) or prices provided by the COPAS Computerized Equipment Pricing System (CEPS).

(a) For oil country tubulars and line pipe, the published price shall be based upon eastern mill carload base prices (Houston, Texas, for special end) adjusted as of date of movement, plus transportation cost as defined in Section IV.2.B (*Freight*).

(b) For other Material, the published price shall be the published list price in effect at date of movement, as listed by a Supply Store nearest the Joint Property where like Material is normally available, or point of manufacture plus transportation costs as defined in Section IV.2.B (*Freight*).

(2) Based on a price quotation from a vendor that reflects a current realistic acquisition cost.

(3) Based on the amount paid by the Operator for like Material in the vicinity of the Joint Property within the previous twelve (12) months from the date of physical transfer.

(4) As agreed to by the Participating Parties for Material being transferred to the Joint Property, and by the Parties owning the Material for Material being transferred from the Joint Property.

B. FREIGHT

Transportation costs shall be added to the Material transfer price using the method prescribed by the COPAS Computerized Equipment Pricing System (CEPS). If not using CEPS, transportation costs shall be calculated as follows:

(1) Transportation costs for oil country tubulars and line pipe shall be calculated using the distance from eastern mill to the Railway Receiving Point based on the carload weight basis as recommended by the COPAS MFI-38 ("Material Pricing Manual") and other COPAS MFIs in effect at the time of the transfer.

(2) Transportation costs for special mill items shall be calculated from that mill's shipping point to the Railway Receiving Point. For transportation costs from other than eastern mills, the 30,000-pound interstate truck rate shall be used. Transportation costs for macaroni tubing shall be calculated based on the interstate truck rate per weight of tubing transferred to the Railway Receiving Point.

(3) Transportation costs for special end tubular goods shall be calculated using the interstate truck rate from Houston, Texas, to the Railway Receiving Point.

(4) Transportation costs for Material other than that described in Sections IV.2.B.(1) through (3), shall be calculated from the Supply Store or point of manufacture, whichever is appropriate, to the Railway Receiving Point

Regardless of whether using CEPS or manually calculating transportation costs, transportation costs from the Railway Receiving Point to the Joint Property are in addition to the foregoing, and may be charged to the Joint Account based on actual costs incurred. All transportation costs are subject to Equalized Freight as provided in Section II.4 (*Transportation*) of this Accounting Procedure.

C. TAXES

Sales and use taxes shall be added to the Material transfer price using either the method contained in the COPAS Computerized Equipment Pricing System (CEPS) or the applicable tax rate in effect for the Joint Property at the time and place of transfer. In either case, the Joint Account shall be charged or credited at the rate that would have governed had the Material been a direct purchase.

D. CONDITION

(1) Condition "A" – New and unused Material in sound and serviceable condition shall be charged at one hundred percent (100%) of the price as determined in Sections IV.2.A (*Pricing*), IV.2.B (*Freight*), and IV.2.C (*Taxes*). Material transferred from the Joint Property that was not placed in service shall be credited as charged without gain or loss; provided, however, any unused Material that was charged to the Joint Account through a direct purchase will be credited to the Joint Account at the original cost paid less restocking fees charged by the vendor. New and unused Material transferred from the Joint Property may be credited at a price other than the price originally charged to the Joint Account provided such price is approved by the Parties owning such Material, pursuant to Section I.6.A (*General Matters*). All refurbishing costs required or necessary to return the Material to original condition or to correct handling, transportation, or other damages will be borne by the divesting property. The Joint Account is responsible for Material preparation, handling, and transportation costs for new and unused Material charged to the Joint Property either through a direct purchase or transfer. Any preparation costs incurred, including any internal or external coating and wrapping, will be credited on new Material provided these services were not repeated for such Material for the receiving property.

(2) Condition "B" – Used Material in sound and serviceable condition and suitable for reuse without reconditioning shall be priced by multiplying the price determined in Sections IV.2.A (*Pricing*), IV.2.B (*Freight*), and IV.2.C (*Taxes*) by seventy-five percent (75%).

Except as provided in Section IV.2.D(3), all reconditioning costs required to return the Material to Condition "B" or to correct handling, transportation or other damages will be borne by the divesting property.

If the Material was originally charged to the Joint Account as used Material and placed in service for the Joint Property, the Material will be credited at the price determined in Sections IV.2.A (*Pricing*), IV.2.B (*Freight*), and IV.2.C (*Taxes*) multiplied by sixty-five percent (65%).

Unless otherwise agreed to by the Parties that paid for such Material, used Material transferred from the Joint Property that was not placed in service on the property shall be credited as charged without gain or loss.

(3) Condition "C" – Material that is not in sound and serviceable condition and not suitable for its original function until after reconditioning shall be priced by multiplying the price determined in Sections IV.2.A (*Pricing*), IV.2.B (*Freight*), and IV.2.C (*Taxes*) by fifty percent (50%).

The cost of reconditioning may be charged to the receiving property to the extent Condition "C" value, plus cost of reconditioning, does not exceed Condition "B" value.

(4) Condition "D" – Material that (i) is no longer suitable for its original purpose but useable for some other purpose, (ii) is obsolete, or (iii) does not meet original specifications but still has value and can be used in other applications as a substitute for items with different specifications, is considered Condition "D" Material. Casing, tubing, or drill pipe used as line pipe shall be priced as Grade A and B seamless line pipe of comparable size and weight. Used casing, tubing, or drill pipe utilized as line pipe shall be priced at used line pipe prices. Casing, tubing, or drill pipe used as higher pressure service lines than standard line pipe, e.g., power oil lines, shall be priced under normal pricing procedures for casing, tubing, or drill pipe. Upset tubular goods shall be priced on a non-upset basis. For other items, the price used should result in the Joint Account being charged or credited with the value of the service rendered or use of the Material, or as agreed to by the Parties pursuant to Section 1.6.A (*General Matters*).

(5) Condition "E" – Junk shall be priced at prevailing scrap value prices.

E. OTHER PRICING PROVISIONS

(1) Preparation Costs

Subject to Section II (*Direct Charges*) and Section III (*Overhead*) of this Accounting Procedure, costs incurred by the Operator in making Material serviceable including inspection, third party surveillance services, and other similar services will be charged to the Joint Account at prices which reflect the Operator's actual costs of the services. Documentation must be provided to the Non-Operators upon request to support the cost of service. New coating and/or wrapping shall be considered a component of the Materials and priced in accordance with Sections IV.1 (*Direct Purchases*) or IV.2.A (*Pricing*), as applicable. No charges or credits shall be made for used coating or wrapping. Charges and credits for inspections shall be made in accordance with COPAS MFI-38 ("Material Pricing Manual").

(2) Loading and Unloading Costs

Loading and unloading costs related to the movement of the Material to the Joint Property shall be charged in accordance with the methods specified in COPAS MFI-38 ("Material Pricing Manual").

**3. DISPOSITION OF SURPLUS**

Surplus Material is that Material, whether new or used, that is no longer required for Joint Operations. The Operator may purchase, but shall be under no obligation to purchase, the interest of the Non-Operators in surplus Material.

Dispositions for the purpose of this procedure are considered to be the relinquishment of title of the Material from the Joint Property to either a third party, a Non-Operator, or to the Operator. To avoid the accumulation of surplus Material, the Operator should make good faith efforts to dispose of surplus within twelve (12) months through buy/sale agreements, trade, sale to a third party, division in kind, or other dispositions as agreed to by the Parties.

Disposal of surplus Materials shall be made in accordance with the terms of the Agreement to which this Accounting Procedure is attached. If the Agreement contains no provisions governing disposal of surplus Material, the following terms shall apply:

- The Operator may, through a sale to an unrelated third party or entity, dispose of surplus Material having a gross sale value that is less than or equal to the Operator’s expenditure limit as set forth in the Agreement to which this Accounting Procedure is attached without the prior approval of the Parties owning such Material.

- If the gross sale value exceeds the Agreement expenditure limit, the disposal must be agreed to by the Parties owning such Material.

- Operator may purchase surplus Condition “A” or “B” Material without approval of the Parties owning such Material, based on the pricing methods set forth in Section IV.2 (*Transfers*).

- Operator may purchase Condition “C” Material without prior approval of the Parties owning such Material if the value of the Materials, based on the pricing methods set forth in Section IV.2 (*Transfers*), is less than or equal to the Operator’s expenditure limitation set forth in the Agreement. The Operator shall provide documentation supporting the classification of the Material as Condition C.

- Operator may dispose of Condition “D” or “E” Material under procedures normally utilized by Operator without prior approval of the Parties owning such Material.

**4. SPECIAL PRICING PROVISIONS**

A. PREMIUM PRICING

Whenever Material is available only at inflated prices due to national emergencies, strikes, government imposed foreign trade restrictions, or other unusual causes over which the Operator has no control, for direct purchase the Operator may charge the Joint Account for the required Material at the Operator’s actual cost incurred in providing such Material, making it suitable for use, and moving it to the Joint Property. Material transferred or disposed of during premium pricing situations shall be valued in accordance with Section IV.2 (*Transfers*) or Section IV.3 (*Disposition of Surplus*), as applicable.

B. SHOP-MADE ITEMS

Items fabricated by the Operator’s employees, or by contract laborers under the direction of the Operator, shall be priced using the value of the Material used to construct the item plus the cost of labor to fabricate the item. If the Material is from the Operator’s scrap or junk account, the Material shall be priced at either twenty-five percent (25%) of the current price as determined in Section IV.2.A (*Pricing*) or scrap value, whichever is higher. In no event shall the amount charged exceed the value of the item commensurate with its use.

C. MILL REJECTS

Mill rejects purchased as “limited service” casing or tubing shall be priced at eighty percent (80%) of K-55/J-55 price as determined in Section IV.2 (*Transfers*). Line pipe converted to casing or tubing with casing or tubing couplings attached shall be priced as K-55/J-55 casing or tubing at the nearest size and weight.

## V. INVENTORIES OF CONTROLLABLE MATERIAL

The Operator shall maintain records of Controllable Material charged to the Joint Account, with sufficient detail to perform physical inventories.

Adjustments to the Joint Account by the Operator resulting from a physical inventory of Controllable Material shall be made within twelve (12) months following the taking of the inventory or receipt of Non-Operator inventory report. Charges and credits for overages or shortages will be valued for the Joint Account in accordance with Section IV.2 (*Transfers*) and shall be based on the Condition “B” prices in effect on the date of physical inventory unless the inventorying Parties can provide sufficient evidence another Material condition applies.

**1. DIRECTED INVENTORIES**

Physical inventories shall be performed by the Operator upon written request of a majority in working interests of the Non-Operators (hereinafter, "directed inventory"); provided, however, the Operator shall not be required to perform directed inventories more frequently than once every five (5) years. Directed inventories shall be commenced within one hundred eighty (180) days after the Operator receives written notice that a majority in interest of the Non-Operators has requested the inventory. All Parties shall be governed by the results of any directed inventory.

Expenses of directed inventories will be borne by the Joint Account; provided, however, costs associated with any post-report follow-up work in settling the inventory will be absorbed by the Party incurring such costs. The Operator is expected to exercise judgment in keeping expenses within reasonable limits. Any anticipated disproportionate or extraordinary costs should be discussed and agreed upon prior to commencement of the inventory. Expenses of directed inventories may include the following:

A. A per diem rate for each inventory person, representative of actual salaries, wages, and payroll burdens and benefits of the personnel performing the inventory or a rate agreed to by the Parties pursuant to Section I.6.A (*General Matters*). The per diem rate shall also be applied to a reasonable number of days for pre-inventory work and report preparation.

B. Actual transportation costs and Personal Expenses for the inventory team.

C. Reasonable charges for report preparation and distribution to the Non-Operators.

**2. NON-DIRECTED INVENTORIES**

A. OPERATOR INVENTORIES

Physical inventories that are not requested by the Non-Operators may be performed by the Operator, at the Operator's discretion. The expenses of conducting such Operator-initiated inventories shall not be charged to the Joint Account.

B. NON-OPERATOR INVENTORIES

Subject to the terms of the Agreement to which this Accounting Procedure is attached, the Non-Operators may conduct a physical inventory at reasonable times at their sole cost and risk after giving the Operator at least ninety (90) days prior written notice. The Non-Operator inventory report shall be furnished to the Operator in writing within ninety (90) days of completing the inventory fieldwork.

C. SPECIAL INVENTORIES

The expense of conducting inventories other than those described in Sections V.1 (*Directed Inventories*), V.2.A (*Operator Inventories*), or V.2.B (*Non-Operator Inventories*), shall be charged to the Party requesting such inventory; provided, however, inventories required due to a change of Operator shall be charged to the Joint Account in the same manner as described in Section V.1 (*Directed Inventories*).

**PREPARED DIRECT TESTIMONY**

**BRANDON BINFORD - GEOLOGIST**

**Q1. Please state your name and identify where you are employed.**

A1. My name is Brandon Binford. I am an Operations Geologist for Antero Resources Corporation. Our offices are located at 1615 Wynkoop Street, Denver, CO 80202.

**Q2. Describe your professional responsibilities at Antero.**

A2. My responsibilities include geology operations and development planning of the Utica/Point Pleasant Formation. I am involved in all phases of Utica/Point Pleasant resource development. The development process starts by identifying the optimum horizontal wellbore azimuth based on multiple data types like microseismic, geophysical and electric logs, and core data. The preferred azimuth direction is based on how the target formation will behave when hydraulically fractured during the completion process. Once I have deciphered the optimum wellbore azimuth, I begin looking for viable surface locations to construct well pads. The horizontal wells are then planned to originate from these surface locations and are planned to be drilled on very specific dates based on a variety of different factors. It is ideal to find well pads that are suitable for multi-well development because this minimizes surface impact and makes the drilling and completion process very efficient. Once the well pad locations have been negotiated with the surface owners, I coordinate with licensed surveyors and our internal regulatory department to secure well permits. After we receive a fully permitted well, I work with directional planning consultants to create suitable wellbore plans, or directional plans, which allow us to drill horizontally, sometimes over 10,000’. Finally, I communicate with the drilling consultants and contractors on the well pad location to successfully drill the lateral wellbore in the targeted stratigraphic interval (i.e. “geosteer” the well). In addition, I do regional Appalachian Basin analysis, detailed structure and isopach mapping, special core analysis, and serve as Geosteering Coordinator for the Utica/Point Pleasant Formation.

**Q3. Describe your educational background.**

A3. I have a Bachelor’s of Science degree in Geology from the Oklahoma State University, with a Minor in Geography. I also have a Master’s of Science degree in Geology from

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the University of Colorado.

**Q4. Describe your professional experience.**

A4. Prior to joining Antero, I spent 4 years at Encana Oil & Gas, where I worked with the DJ, Raton, North Park, Piceance, Douglas Creek, Arch, Uinta, and Permian Basins. I have various tight gas sands and shale experience ranging from exploration to development and operations. I have spent the past year and a half at Antero Resources, where I work on Marcellus Shale and Utica/Point Pleasant Formation operations and development.

**Q5. Are you a member of any professional associations?**

A5. I am a member of American Association of Petroleum Geologists, Rocky Mountain Section; Society of Petrophysics and Well Log Analysis; Society of Exploration Geophysicists; and the Denver Geophysical Society.

**Q6. Are you familiar with Antero Resources Corporation's Application for Unit Operations with respect to the Siberian Unit?**

A6. Yes.

**Q7. Describe the Siberian Unit, in terms of its general location, surface acreage, and subsurface depth?**

A7. The Siberian Unit consists of 37 separate tracts of land totaling approximately 702.245 acres in Noble and Monroe Counties, Ohio. Exhibit 1-A.2 to the Unit Agreement shows the geologic location of the proposed unit in Noble and Monroe Counties. The Unitized Formation described in the Application is the subsurface portion of the Siberian Unit at a depth from 50' above the top of the Utica Shale, to 50' below the base of the Point Pleasant Formation.

**Q8. Ohio Revised Code § 1509.01(E) defines the term "pool" to mean "an underground reservoir containing a common accumulation of oil or gas, or both, but does not include a gas storage reservoir. Each zone of a geological structure that is completely separated from any other zone in the same structure may contain a separate pool." Please explain if this definition of "pool" applies to the Siberian Unit and why?**

A8. My personal understanding of a pool is an area of geologically consistent reservoir properties such as thickness, porosity, resistivity, and rock type that share an accumulation

EXHIBIT 2

of hydrocarbons. Those hydrocarbons will be produced together using one or more wellbores across a unit. Outside of the defined unit, the formation will not be affected and reserves will not be depleted. I do think that the Siberian Unit falls under my definition of “pool” and, likewise, the Ohio Revised Code definition of pool.

**Q9. How do geologists investigate the geologic characteristics of a shale play such as the Utica/Point Pleasant formation?**

A9. Geologists rely on previous literature and geologic studies and look at various factors, including porosity, resistivity, and gamma ray analysis through wireline logging, formation micro-resistivity imaging analysis through wireline logging, cores and cuttings, outcrops, geochemistry and thermal maturity, microseismic mapping projects and analysis, mudlogging information and drill bit behavior.

**Q10. Generally speaking, what sources of data would you review and analyze in order to assess the geologic characteristics of a potential shale play?**

A10. The majority of our geologic understanding of the Utica/Point Pleasant comes from the analysis of whole cores, drill cuttings, and wireline log analysis. I spend considerable time comparing wireline log data readings to core data. These comparisons are then used to derive correlations between well production and reservoir characteristics. I also use basin studies to assist in my assessment of a potential shale play. I examine both burial history and depositional setting. These two criteria give geologists an idea of the conditions of deposition, and what has happened to that formation since. A shale play, for example, is characteristically identified with deposits in a relatively deep water anoxic environment with little to no tidal influence. Once it was laid down and other layers deposited on top of it, tectonics and burial would contribute to the maturation of the organic particles contained within the shale. Those organic particles would at some point go through hydrocarbon generation and maturation. Areas of greater depth, temperature, and pressure will have greater thermal maturity and drier gas. Due to the fact that shale reservoirs are self-sealing and have very low permeability, there is less of a need to identify a confining or “trapping” geologic unit above the resources, as would be typical with conventional plays. Therefore, shale reservoirs are commonly referred to as unconventional resource plays.

**Q11. How is this data obtained, and what is it meant to show about the formation?**

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A11. Wireline log data is obtained from vertical wells called “pilot wells” and older exploration wells that penetrated the current zone of interest – in this case the Utica/Point Pleasant Formation. Wireline data gives geologists a way to determine reservoir properties without having to physically sample the rock. Where operators drill pilot wells, the core data rock properties and advanced logging suites (e.g. FMI, ECS, and Sonic Scanner) are modeled to match the wireline data. Those models are then applied to nearby wells to determine reservoir quality.

**Q12. What data sources did you use in determining the geologic features of the Siberian Unit?**

A12. I used wireline logs from surrounding wells, cores from the Miley Unit 5H Pilot well, and microseismic data from the Wayne Unit Pilot.

**Q13. Which formations are included in the proposed Siberian Unit?**

A13. The Utica Shale and Point Pleasant Formations.

**Q14. How and why were these formations chosen?**

A14. The Utica Shale and Point Pleasant Formation were chosen to be part of the Siberian Unit because we believe they are both part of the same pool. We will drill a target zone in the Point Pleasant Formation, but believe our hydraulic fracturing operations will go through the Point Pleasant and into the Utica Shale.  Based on our geologic understanding of the Utica Shale and Point Pleasant Formation, the main reservoir is the Point Pleasant Formation. That is from where most of the hydrocarbons are produced. However, we have seen natural fracturing, porosity, and oil/gas accumulation in cores taken from the Utica Shale, and believe that our hydraulically created fractures will penetrate and drain a small portion of that formation.

**Q15. What is the approximate depth of the Utica/Point Pleasant Formation under the Siberian Unit?**

A15. The approximant depth of the top of the Utica Formation is 7,995’ TVD and the Point Pleasant Formation is 8,100’ TVD.

**Q16. Please describe your Exhibits and summarize what they tell us about the Siberian Unit.**

A16. Exhibit 2-A is a map of southeastern Ohio showing the area where the Siberian Unit is being proposed, highlighted in pink, as well as several key producing Utica/Point Pleasant horizontal wells. Exhibit 2-B is Cross Section A-A' of three keys wells surrounding the Siberian Unit, the Miley Unit 5H Pilot, Et Rubel 1 Pilot, and Wolf Pen Pilot(see Exhibit 2-A for location of the cross section wells). The log data displayed are gamma ray in track 1 and resistivity in track 2. As particularly seen on this exhibit the log data show that the Utica/Point Pleasant Formation does not change within or across the proposed Siberian Unit; the stratigraphy is regionally very consistent. Geologic properties, like thickness and resistivity, are constant throughout the Siberian Unit.

**Q17. Based on the data you analyzed, should the area be considered a pool? Explain why.**

A17. Yes. The log data demonstrate that formation thickness remains relatively constant across the unit. Porosity and resistivity will be relatively uniform, and the thermal maturity of the rock, which applies to BTU and liquids content, is the same across the unit. Based on the foregoing, in my professional opinion, the area within the proposed Siberian Unit boundary is all one geologic unit, or part of the same pool.

**Q18. Given the reservoir characteristics of the Utica/Point Pleasant Formation, what would be an appropriate method of allocating production and unit expenses among the parcels contained in the Siberian Unit?**

A18. An appropriate method of allocation would be on a surface acreage basis. The relative thickness and reservoir quality of the Utica/Point Pleasant Formation is expected to be consistent across the Siberian Unit. There are no substantial variations expected across the proposed unit and therefore there is no geologic reason to allocate production using a method other than surface acreage.

**Q19. Is this the method proposed by Antero for the Siberian Unit?**

A19. Yes.

**Q20. Is this method used elsewhere?**

A20. Yes. Antero has used this method on all of the units that we have drilled in Ohio to date. My understanding is that similar methods for pooling are used in Colorado, Oklahoma, and possibly other states as well.

**Q21. Does this conclude your testimony?**

A21. Yes.



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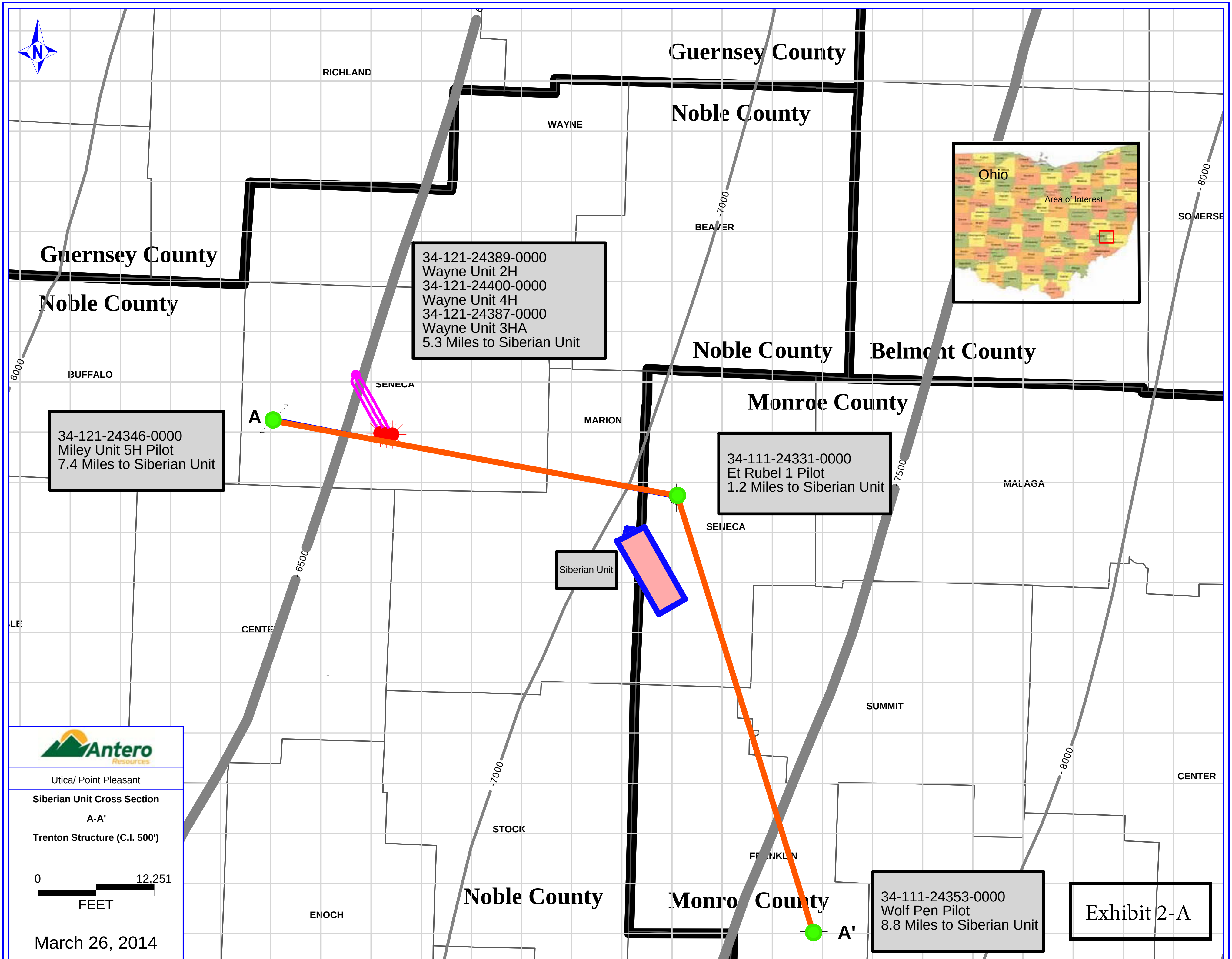


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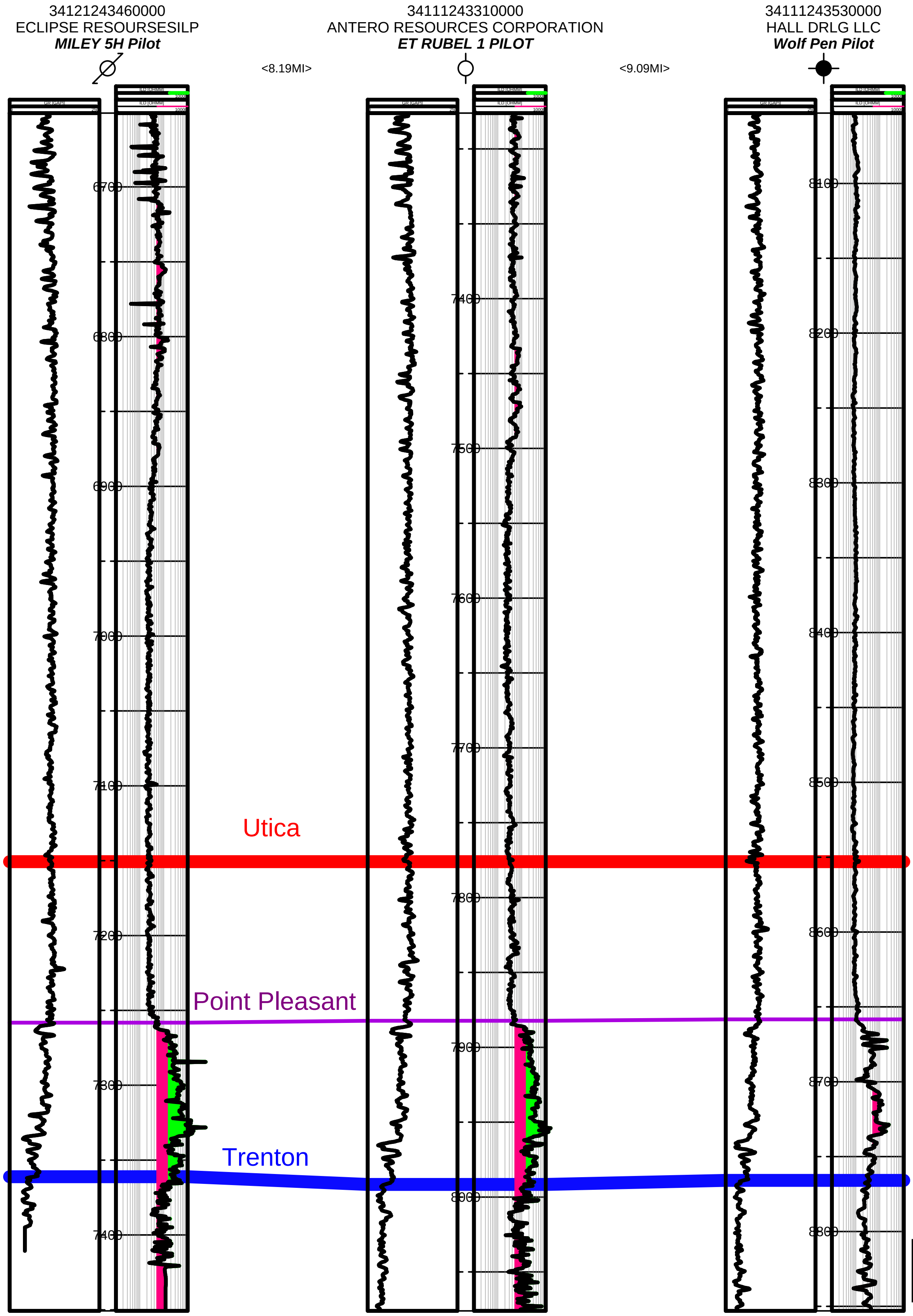


# Exhibit 2-B

Appalachian Basin - Utica Shale

West-East Stratigraphic Cross Section

Siberian Unit Offset Cross Section

Flattened on Utica Shale Top
Gamma Ray Log (0-250 API)
Resistivity Logs (1-10,000 OHMM)

By: Sy Luke

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# PREPARED DIRECT TESTIMONY

# HAL HOGSETT

**Q1. What is your name and business address?**

A1. My name is Hal Hogsett. I am a Reservoir Engineer with Antero Resources Corporation. My business address is 1615 Wynkoop Street Denver, Colorado 80202

**Q2. Can you please describe your educational background?**

A2. I hold a Bachelors of Science degree in Petroleum Engineering from The University of Texas in Austin.

**Q3. Describe your professional experience.**

A3. I have approximately seven years of experience working in oil and gas development and exploration. I have been with Antero Resources for two years as a Reservoir Engineer working the Appalachian Basin and Piceance Basin. Prior to working for Antero Resources, I worked with Apache Corporation in multiple disciplines including drilling, completion, production, reserves, reservoir simulation, and field operations. Other than the Appalachian basin, I have worked the Anadarko Basin, Gulf Coast, Gulf of Mexico, and the Permian Basin.

**Q4. Are you a member of any professional associations?**

A4. I have been a member of the Society of Petroleum Engineers for nine years in Colorado, Oklahoma and Texas. I am also a member of the Young Professionals in Energy, where I have previously held an executive board position.

**Q5. What does being a Reservoir Engineer entail?**

A5. As a Reservoir Engineer at Antero Resources, I am responsible for quantifying hydrocarbon volumes in the Utica/Point Pleasant Shale formation. I prepare quarterly SEC reserve estimates for the Utica. I coordinate gathering of data such as PVT sampling, gas analysis along with pressure surveys used in preparing reserve estimates. Some of the tools I use to estimate reserves include decline curve analysis, rate transient analysis, and volumetric calculations.

**Q6. With regard to the Siberian Unit, have you made an estimate of the production you anticipate from the proposed unit's operations?**



EXHIBIT 3

A6. Yes, it is estimated that if the Siberian Unit was developed by drilling five laterals greater than 9,400' as proposed, 702 acres would be effectively developed and 91.0 Bcfe would be recovered. The calculations are summarized in Exhibit 3-A.

**Q7. How did you make the estimates?**

A7. Using well production data, well test data, analogous shale plays, log data, PVT analysis, and reservoir simulation, I generated a type curve for a well in the Utica/Point Pleasant Shale. The reserves applied to the five wells in the Siberian Unit have been estimated based on these type curves. This process is recognized throughout all North American shale plays.

**Q8. If the Siberian Unit as proposed were not granted, have you estimated the production that could be recovered?**

A8. Yes, if we were not able to unitize the Siberian unit, two of the five laterals could not be fully developed. Drilling two shorter laterals would allow us to develop only 594 of the planned 702 acres. I have estimated the quantity of reserves attributable to drilling these two shorter laterals to be 21.4 Bcfe. Without unitization, the reserves to the southern portion of the proposed unit would be stranded and not produced. Thus, of the 91.0 Bcfe potentially recoverable reserves, only 75.9 Bcfe could be produced, leaving 15.1 Bcfe stranded.

**Q9. In your professional opinion, would it be economic to develop the Siberian Unit using traditional vertical drilling?**

A9. No, vertical well drilling is more applicable in a thicker, more permeable productive interval. Horizontal drilling, utilizing hydraulic fracturing is necessary in tight shale formations such as the Utica/Point Pleasant in order to increase the surface area exposed to the hydrocarbon bearing reservoir. This provides more conduits by which the hydrocarbons can be drained. Without horizontal drilling and stimulation, the permeability is too low to produce sufficient quantities of product to justify the expense of drilling.

**Q10. Summarize what your calculations show and the differences between unitized vs non-unitized development?**

A10. The results of my calculations are summarized in Exhibit 3-A. In the Unitized development plan, we would develop 702 acres of the Utica/Point Pleasant by drilling five wells greater than 9,400’ in length. We would do this from an existing pad, where we have existing pipelines to move the product. Without unitization, we would only be able to develop 594 acres by drilling 5 wells of 9,648’, 5,624’, 5,627’, 9,540’, and 9,440’ lateral lengths. With unitization we would be able to drill 20% additional lateral feet and develop 18% more acreage from the same surface footprint. With unitization, we would recover an incremental 20% of otherwise stranded hydrocarbons.

**Q11. Is the increase in production associated with unitization solely due to drilling the currently unleased parcels?**

A11. No, the increased production is not solely attributable to production associated with the unleased parcels, but also the production from all of the acreage that would otherwise be stranded without unitization. Aside from the 0.064 unleased acres, there are a number of leased parties who would like to participate in the Siberian Unit. These mineral owners have willingly entered into leases which allow for the production of oil and gas from their property, but because Antero must legally stay 500’ away from unleased tracts, their property cannot be developed without unitization. Their interest would be stranded and likely never developed if unitization is not granted. See Exhibit 4-A for a visual representation of the stranded acreage.

**Q12. Do you believe that the proposed unit operations are reasonably necessary to increase substantially the ultimate recovery of oil and gas from the unit area?**

A12. Absolutely. Without unitization we would be stranding 15.1 Bcfe of hydrocarbons under the proposed Siberian Unit. I believe that the proposed unitization of the Siberian Unit is necessary to be protective of correlative rights of all mineral owners within the unit while effectively and prudently maximizing recovery of hydrocarbons.

**Q13. Would you walk us through your economic evaluation, beginning with your estimate of the anticipated revenue stream from the Siberian Unit development?**

A13. During the reserve estimation process, a production profile was generated to estimate produced volumes over time. This, along with a specific pricing scenario, is essential in generating revenues attributable to a well or a project. I have estimated capital requirements based on each well’s lateral length. Each well assumes the same operating expense model and pricing. Once I have anticipated future volumes generated for each



EXHIBIT 3

well, I discount the revenue in order to generate a net present value and return for the project.

**Q14. What price scenario did you use?**

A14. For preparation of economics, SEC pricing was used. 1Q2014 basis pricing for gas was $3.86/MMBTU. I also included NGLs attributable to gas processing in my economic analysis. It is estimated that gas in this area is approximately 1170 BTU. SEC pricing for NGLs is $49.99/bbl for 1170 BTU gas. A company will run several pricing scenarios when evaluating a project. SEC pricing is a trailing 12-month average basis price projected flat into the future. This eliminates the fluctuation of strip pricing projections from varying sources. SEC pricing is used when preparing reserves on a quarterly basis and therefore is consistently recognized as a reliable convention among oil and gas exploration companies.

**Q15. What about anticipated capital and operating expenses?**

A15. Capital and operating expenses were incorporated in my analysis. The total estimated capital is based on the capital costs for both the drilling and completion process. The basis for this estimate comes from recent costs we have experienced and incurred in our early Utica success. Our operations group prepares a cost estimate for various lateral lengths, which are then scaled based on the respective lateral length of each well in the Siberian Unit. The operating expenses are based on operating experience we have from similar operating areas in Ohio and West Virginia. I look at total operating costs allocated to each well, which are then categorized as a fixed or variable cost. Operating costs incorporated in this analysis are both fixed and variable cost estimates.

**Q16. Did you consider whether a different, smaller unit could be developed by locating the well pad somewhere else?**

A16. Yes, however there was not a feasible solution for alternative development. Other potential pad locations were ruled out due to topography, culture, and setback from dwelling requirements. We would not be able to drill the stranded acreage from the south due to technical limits of lateral lengths. As previously noted, a preexisting pad serves additional wells to the North of the proposed Siberian Unit. Utilizing this existing pad maximizes efficiency, minimizes surface disturbance, and is the most sensible decision operationally, environmentally, and economically.

**Q17. Based on this information and your professional judgment, does the value of the estimated additional recovery of hydrocarbons from the unitized project exceed its estimated costs?**

A17. Yes. The capital expense is $74.1 million for the unitized project, as compared to $64.7 million for the non-unitized project. The value of hydrocarbons from the proposed unit is $94.7 million as compared to $76.2 million without approval of this application for unit operations. For an additional $9.4 million in capital, Antero could recover hydrocarbons valued at $18.5 million. Thus, the economic benefits of unitization far outweigh the additional costs necessary for unit development.

**Q18. Does this conclude your testimony at this time?**

A18. Yes.



EXHIBIT 3

**Exhibit 3-A - Antero Siberian Unit Unitization Engineering Testimony**

| Unitized Siberian Unit (Optimum Development) | | | | | | | |
|---|---|---|---|---|---|---|---|
| Well Name | Lateral Length (feet) | Acres Developed | Gross Capital ($MM) | Net PV10 ($MM) | Gross Residue Gas (Bcf) | Gross Processed NGLs (Mbbls) | Gross Reserves (Bcfe) |
| Siberian Unit 1H | 9,648 | 142 | $ 14.9 | $ 19.2 | 15.9 | 416 | 18.4 |
| Siberian Unit 2H | 9,557 | 140 | $ 14.8 | $ 18.9 | 15.7 | 412 | 18.2 |
| Siberian Unit 3H | 9,641 | 142 | $ 14.9 | $ 19.1 | 15.9 | 415 | 18.4 |
| Siberian Unit 4H | 9,540 | 140 | $ 14.8 | $ 18.9 | 15.7 | 411 | 18.2 |
| Siberian Unit 5H | 9,440 | 139 | $ 14.7 | $ 18.7 | 15.5 | 407 | 18.0 |
| Total Siberian Unit | 47,826 | 702 | $ 74.1 | $ 94.7 | 78.7 | 2,061 | 91.0 |

| Non-Unitized Siberian Unit (Stranded Reserves) | | | | | | | |
|---|---|---|---|---|---|---|---|
| Well Name | Lateral Length (feet) | Acres Developed | Gross Capital ($MM) | Net PV10 ($MM) | Gross Residue Gas (Bcf) | Gross Processed NGLs (Mbbls) | Gross Reserves (Bcfe) |
| Siberian Unit 1H | 9,648 | 142 | $ 14.9 | $ 19.2 | 15.9 | 416 | 18.4 |
| Siberian Unit 2H | 5,624 | 87 | $ 10.2 | $ 9.8 | 9.3 | 242 | 10.7 |
| Siberian Unit 3H | 5,627 | 87 | $ 10.2 | $ 9.8 | 9.3 | 242 | 10.7 |
| Siberian Unit 4H | 9,540 | 140 | $ 14.8 | $ 18.9 | 15.7 | 411 | 18.2 |
| Siberian Unit 5H | 9,440 | 139 | $ 14.7 | $ 18.7 | 15.5 | 407 | 18.0 |
| Total Siberian Unit | 39,879 | 594 | $ 64.7 | $ 76.2 | 65.6 | 1,718 | 75.9 |

| Difference | | | | | | | |
|---|---|---|---|---|---|---|---|
| Well Name | Lateral Length (feet) | Acres Developed | Gross Capital ($MM) | Net PV10 ($MM) | Gross Residue Gas (Bcf) | Gross Processed NGLs (Mbbls) | Gross Reserves (Bcfe) |
| Siberian Unit 1H | - | - | $ - | $ - | - | - | - |
| Siberian Unit 2H | 3,933 | 54 | $ 4.6 | $ 9.2 | 6.5 | 169 | 7.5 |
| Siberian Unit 3H | 4,014 | 55 | $ 4.7 | $ 9.4 | 6.6 | 173 | 7.6 |
| Siberian Unit 4H | - | - | $ - | - | - | - | - |
| Siberian Unit 5H | - | - | $ - | - | - | - | - |
| Total Siberian Unit | 7,947 | 108 | $ 9.4 | $ 18.5 | 13.1 | 342 | 15.1 |
| Incremental % | 20% | 18% | 15% | 24% | 20% | 20% | 20% |

**Exhibit 3-A**

| **Siberian Operating Costs** | | **($M)** |
|---|---|---|
| Lease Operating Expenses | $ | 108 |
| Gathering/Compression | $ | 1,478 |
| NGL Processing (required to meet pipeline spec.) | $ | 1,398 |
| | | |
| First Year Estimated Annual Operating Costs (Per Well) | $ | 2,984 |

*Subsequent years would decrease, as the majority of these costs are dependent on production volumes

**PREPARED DIRECT TESTIMONY**

**SLOANE FORD –LANDMAN**

**Q1. Please state your name and identify your employer.**

A1. My name is Sloane Ford and I am a Landman with Antero Resources Corporation. Antero is a Denver based exploration and production company engaged in the development of oil and gas properties in the Appalachian Basin. Our offices are located at 1615 Wynkoop Street Denver, Colorado 80202.

**Q2. As a Landman, what are your professional responsibilities?**

A2. As a Landman I am responsible for managing field brokers, negotiating lease acquisitions, and handling title matters for our operations in the Utica Shale. I have also been responsible for overseeing our unitization efforts with regard to the subject Unit.

**Q3. Please summarize your educational background.**

A3. I graduated from the University of Oklahoma with a Bachelor's degree in Business Administration with an emphasis in Energy Management.

**Q4. What is your employment history?**

A4. I began working for Chesapeake Energy in April of 2010 based in Oklahoma City, OK. I worked the Barnett Shale located in Fort Worth, TX for the two years I spent at Chesapeake. I began working for Antero in March of 2012. I have been working the Marcellus Shale located in West Virginia for the past two years. I have recently started working the Utica Shale, where I will be a part of developing the play through lease acquisitions and negotiations, acreage exchanges, title review, unit formation, wellbore planning, joint operating agreement negotiations, various permitting responsibilities, as well as other related Landman duties.

**Q5. Do you belong to any professional organizations or associations?**

A5. I am a member of the American Association of Professional Landmen and the Denver Association of Professional Landmen.

**Q6. Do you have any prior experience with unitization applications?**

A6. I have been involved with pooling, or other unitization statutes, of oil and gas interests in each of the states that I have worked in and have been involved with the preparation of this Application for the Siberian Unit.



EXHIBIT 4

**Q7. Can you briefly describe the proposed Siberian Unit?**

A7. The Siberian Unit consists of 37 separate tracts of land, totaling 702.245 acres more or less in Noble and Monroe Counties, Ohio.

**Q8. What are Antero's plans for developing the Siberian Unit?**

A8. Within the Siberian Unit we are currently planning to drill and complete five horizontal wells, all to be drilled from the same surface location at the north end of the Unit. Exhibit 4-A depicts the surface location as well as the planned wellbore path for each of the five Siberian Unit wells. Development of the Utica in this manner is ideal as it provides several economic and environmental benefits. Drilling, completing, and producing multiple horizontal wells from a single surface location provides maximum production efficiency while substantially reducing the disturbed area and surface impact. This type of development will also protect the correlative rights of the mineral and working interest owners within the unit.

**Q9. What is Antero's Interest in the Siberian Unit?**

A9. Antero owns the oil and gas rights to 702.181 acres of the proposed 702.245 acre unit, which is 99.99089% of the Unit.

**Q10. Could you please expound on Antero's interest in this Unit?**

A10. Through Antero's leasing activity and leasehold acquisitions in this general area, and this Unit specifically, we have secured the working interest rights as to all but two very small tracts located in the Siberian Unit. The two tracts that we have not been able to secure are both owned by the Ohio Department of Transportation, who has refused or been unable to sign an oil and gas lease. Despite numerous attempts to work out a lease agreement, or any alternative arrangement to obtain the mineral rights, we have been unable to work anything out with ODOT. The two tracts in question total 0.064 net mineral acres.

**Q11. Can you provide additional information regarding your discussions with ODOT and your attempts to work out an agreement?**

A11. In September of 2013 we discovered that ODOT owned the minerals as to these two small tracts in Monroe County. Recognizing that Monroe County is part of "District 10" Max Green made several attempts to contact the Real Estate Administrator of District 10, Sarah Pepper. Ms. Pepper referred Mr. Green to John Maynard who is the Real Estate



EXHIBIT 4

Administrator for the Division of Engineering at ODOT's Central Office in Columbus. After several months and numerous discussions with Mr. Maynard, Mr. Green was advised that ODOT could not and would not execute a lease and therefore Unitization was likely our only option. The attached lease log [Exhibit 4-D] further details those dealings with ODOT.

**Q12. Can you briefly summarize the terms of the Unit Agreement?**

A12. The Unit Agreement, which is attached to this application as Exhibit 1 combines the oil and gas rights as to fifty feet above the top of the Utica Shale to fifty feet below the base of the Point Pleasant formation, such that we can uniformly operate the Siberian Unit as though it were a single lease. Pursuant to the Unit Agreement, we will allocate the production proceeds from the Siberian Unit among royalty interest owners based on a surface-acreage basis. Our geology testimony stated that the target formation thickness and reservoir quality of the Utica formation is expected to be consistent across the entire unit and therefore allocation based on surface acreage is appropriate. Under the surface acreage allocation, each tract will be given its proportionate percentage by dividing the tract acreage by the total unit acreage, both of which have been calculated by certified survey.

**Q14. How are unit expenses paid?**

A14. Unit expenses will be allocated and paid by the working interest owners using the same method. Antero is the only working interest owner in this Unit and therefore will be responsible for all Unit expenses. Royalty interest owners will not pay unit expenses and will only be responsible for their proportionate share of taxes and post-production costs, which will be payable only from their share of proceeds.

**Q15. Who makes decisions about how the Unit is operated?**

A15. Antero is the Unit Operator and will make the operations decisions for the unit.

**Q16. How does Antero propose treating the unleased party within this Unit?**

A16. We are requesting that the unleased owner be offered two fair market options under which its interest will be compelled into the unit, which would allow us to develop this unit as planned in the most efficient way possible, while also providing their owners with fair compensation for the inclusion and development of their minerals. Accordingly, we



EXHIBIT 4

request that the Chief's Unitization Order give the unleased party a 30 day option to select from the following options:

(1) Upfront consideration of $7,000 per acre plus an 18% royalty [High Bonus Option] of the oil and gas produced from any well drilled pursuant to the Order, free and clear of all costs, expenses and risks incurred in connection with the drilling and completing any such well; provided that such royalty shall be payable only as to the proportionate amount the acreage placed into the unit bears to the total acreage in the unit.

(2) Upfront consideration of $6,000 per acre plus a 20% royalty [High Royalty Option] of the oil and gas produced from any well drilled pursuant to the Order, free and clear of all costs, expenses and risks incurred in connection with the drilling and completing any such well; provided that such royalty shall be payable only as to the proportionate amount the acreage placed into the unit bears to the total acreage in the unit.

The interest relinquished under the above options would be limited in depth and time as to the unitized formations and the term of the Unitization Order. Moreover, there would be no surface operations authorized unless specifically agreed to by Antero and the unleased owner. If the unleased party does not make a selection within the 30 day timeframe, we request that the Chief's Unitization Order treat the unleased party as if it had selected the High Bonus Option.

**Q17. Is this a fair offer in your opinion?**

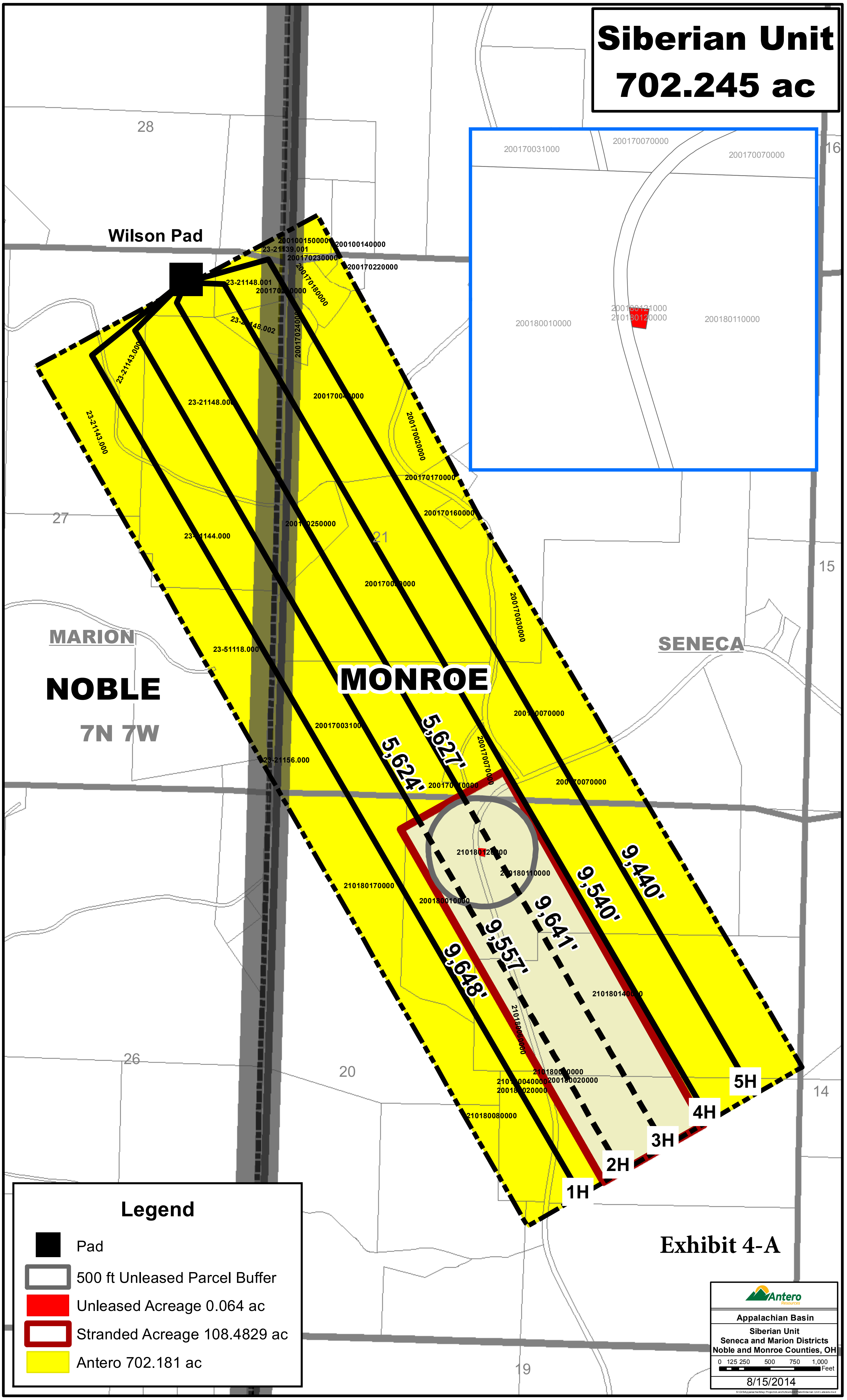
A17. Yes. The two options provided represent the current market value of leasing in this unit, which was determined by looking at the open market transaction over the past year within the unit. Therefore, I believe that the options above would provide an equitable solution to both the leased and unleased owners.

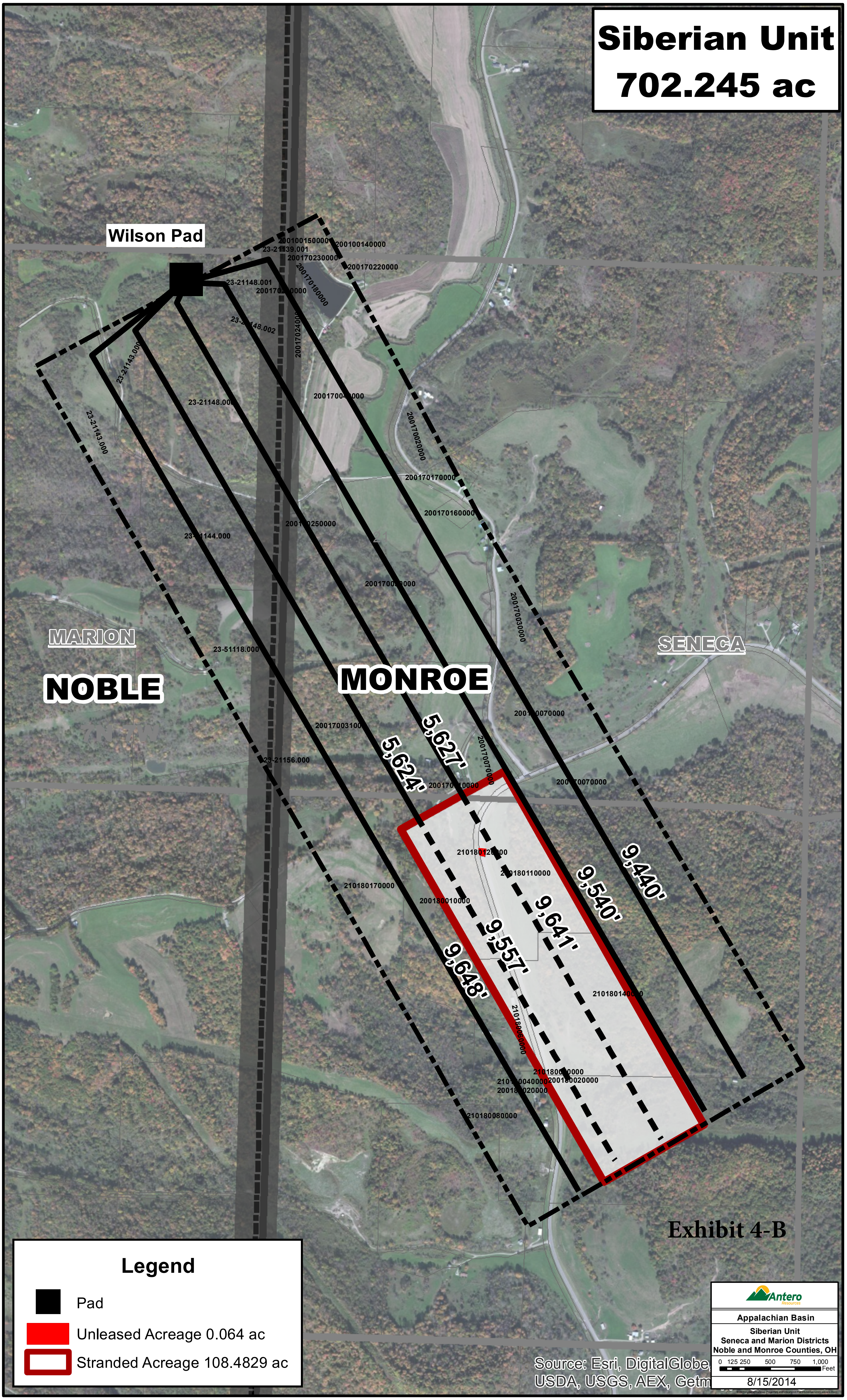
**Q18. Does this conclude your testimony?**

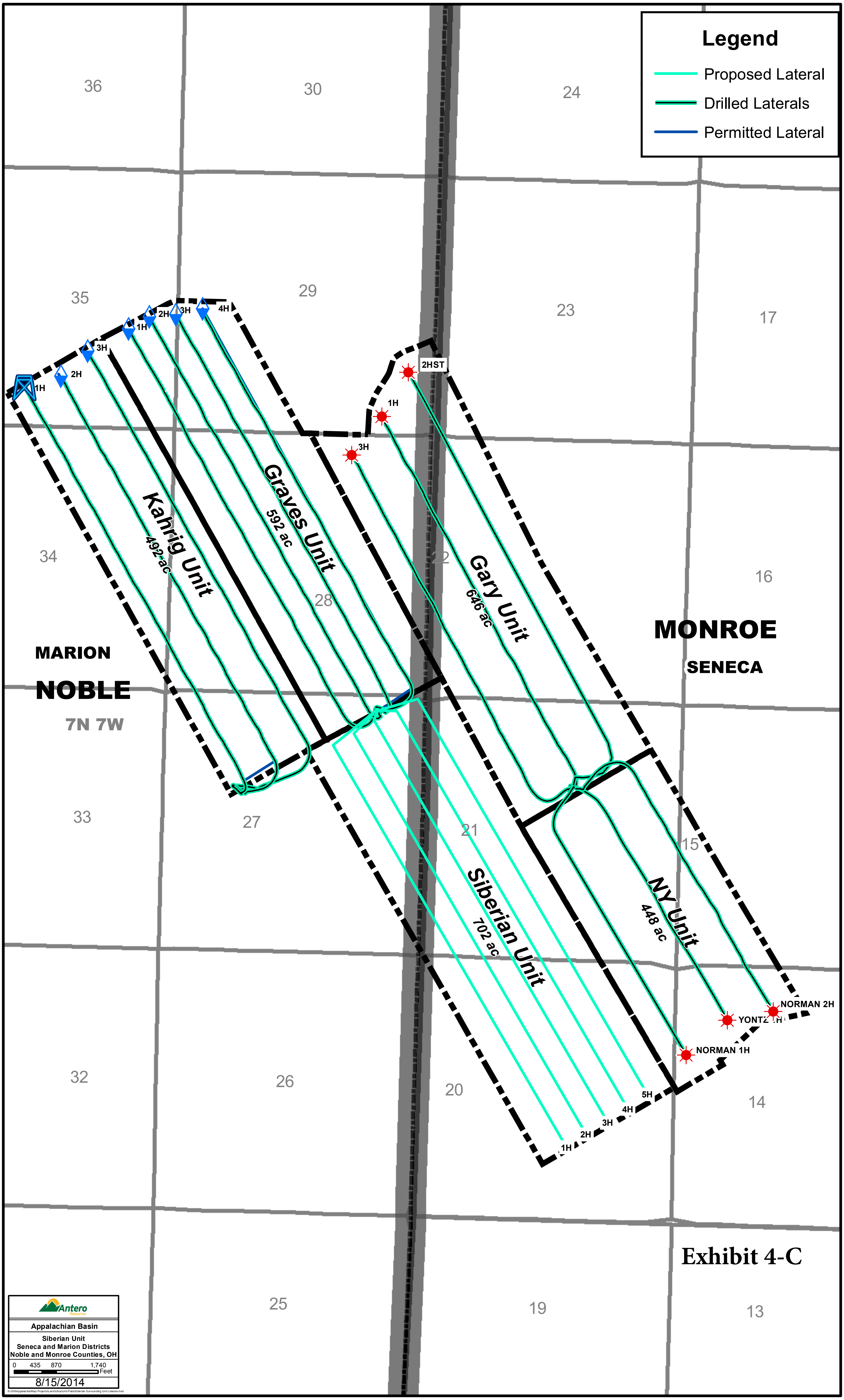
A18. Yes.



EXHIBIT 4


Siberian Unit
702.245 ac
Wilson Pad
MARION
NOBLE
7N 7W
MONROE
SENECA
5,624'
5,627'
9,648'
9,557'
9,641'
9,540'
9,440'
1H
2H
3H
4H
5H
28
27
26
21
20
19
16
15
14
Legend
Pad
500 ft Unleased Parcel Buffer
Unleased Acreage 0.064 ac
Stranded Acreage 108.4829 ac
Antero 702.181 ac
Exhibit 4-A
Antero Resources
Appalachian Basin
Siberian Unit
Seneca and Marion Districts
Noble and Monroe Counties, OH
0 125 250 500 750 1,000 Feet
8/15/2014


Siberian Unit
702.245 ac
Wilson Pad
MARION
NOBLE
MONROE
SENECA
5,627'
5,624'
9,440'
9,540'
9,641'
9,557'
9,648'
Exhibit 4-B
Legend
Pad
Unleased Acreage 0.064 ac
Stranded Acreage 108.4829 ac
Antero
Appalachian Basin
Siberian Unit
Seneca and Marion Districts
Noble and Monroe Counties, OH
0 125 250 500 750 1,000
Feet
8/15/2014



Legend
Proposed Lateral
Drilled Laterals
Permitted Lateral
36
30
24
35
29
23
17
34
28
22
16
33
27
21
15
32
26
20
14
25
19
13
Kahrig Unit
492 ac
Graves Unit
592 ac
Gary Unit
646 ac
Siberian Unit
702 ac
NY Unit
448 ac
1H
2H
3H
4H
5H
2HST
NORMAN 2H
NORMAN 1H
MARION
NOBLE
7N 7W
MONROE
SENECA
Exhibit 4-C
Antero Resources
Appalachian Basin
Siberian Unit
Seneca and Marion Districts
Noble and Monroe Counties, OH
0 435 870 1,740 Feet
8/15/2014
S:\GIS\Appalachia\Map Projects\Land\Utica\Unit Plats\Siberian Surrounding Unit Laterals.mxd

**AFFIDAVIT OF LEASE EFFORTS**

STATE OF OHIO )
) SS
COUNTIES OF NOBLE AND MONROE )

The undersigned, being first duly sworn according to the law, makes this Affidavit and deposes and says that:

1. Affiant, Sloane Ford, is employed by Antero Resources Corporation ("Antero") as a Landman. Affiant's job responsibilities include managing field land brokers, negotiating lease acquisitions, and handling title matters for Antero's operations in the Utica Shale.
2. As a result of her job responsibilities, Affiant has personal knowledge of the matters set forth in this affidavit, including the attachment hereto, and the following information is true to the best of Affiant's knowledge and belief.
3. Antero has made diligent efforts to voluntarily lease all of the oil and gas interests within the proposed Siberian Unit and, as of the date of this affidavit, had leased more than 99% of those interests.
4. Despite Antero's efforts, two (2) tracts remain unleased.
5. The attached chart documents, in summary form, Antero's efforts to lease each such unleased tract, which efforts include mailing lease offers by certified mail, placing telephone calls, making in-person visits, corresponding by e-mail, or some combination of the above.
6. Antero continues to negotiate with the unleased landowner in an ongoing effort to obtain additional leases before the hearing on the Unit Application for the Siberian Unit.

Further Affiant sayeth naught.

Dated this 13 day of May, 2014.

Sloane Ford

Sloane Ford, Affiant
Landman
Antero Resources Corporation

EXHIBIT 4-D

## ACKNOWLEDGEMENT

STATE OF COLORADO )
) SS
COUNTY OF Denver )

The foregoing instrument was sworn to before me, a Notary Public in and for the State of Colorado, and subscribed in my presence this 13 day of May, 2014, by Sloane Ford, known to me or satisfactorily proven to be the Affiant in the foregoing instrument, who acknowledged the above statements to be true as Affiant verily believes.

IN WITNESS WHEREOF, I hereunto set my hand and official seal.

My Commission Expires:

______________________

Lauren Schopp
Notary Public

LAUREN SCHOPP
Notary Public
State of Colorado
Notary ID 20134057501
My Commission Expires Sep 13, 2017

(SEAL)

Lauren Schopp
Printed Name of Notary

| Tract | Owner | Parcel | Net Acres |
|---|---|---|---|
| 25 | | 20-18012.100 | 0.034 |
| 28 | State of Ohio | 21-18012.000 | 0.030 |

| Date | Comments |
|---|---|
| Nov. 2013 | Max Green made several attempts to contact Sara Pepper (Real Estate Administrator - District 10)regarding unleased interest. Upon speaking with Ms. Pepper Mr. Green was referred to Jim Viau (Manager, Relocation and Property Management Section - ODOT Central Office) |
| Dec. 2013 | Max Green attempted to contact Mr. Viau daily throughout the first two weeks of December |
| 12/18/2013 | Max Green Spoke to Jim Viau's secretary, Stephanie, and was referred to John Maynard (Administrator, Office of Real Estate - ODOT Central Office) |
| 01/07/2014 | Max Green spoke with Mr. Maynard regarding the unleased interest. Our offer to lease @ $5,500/acre and 20% royalty was extended verbally. |
| 01/09/2014 | Antero mailed its lease offer to the attention of Jim Viau with a carbon copy to Mr. Maynard as requested by Mr. Maynard |
| 01/15/2014 | Max Green attempted to set up an in person meeting with Mr Maynard at ODOT's central office to discuss the lease. Mr Maynard was unavailable to meet but did confirm receipt of Antero's lease packet and offer |
| Jan. 15 - Feb. 28, 2014 | Max Green and John Maynard exchanged several calls in which Mr. Maynard indicated that ODOT may be getting closer to making a decision regarding the lease |
| 03/13/2014 | Max Green attempted an in person visit at ODOT's central office, however, Mr. Maynard was unavailable to meet |
| 03/18/2014 | Max Green spoke to Mr. Maynard who indicated that ODOT could not and would not execute a lease and that Unitization was likely our only option |

WORKING INTEREST OWNER

APPROVAL OF

UNIT PLAN FOR THE

SIBERIAN UNIT

Marion and Seneca Townships

Noble and Monroe Counties, Ohio

KNOW ALL MEN BY THESE PRESENTS:

WHEREAS, a Unit Plan has been prepared for the testing, development, and operation of certain Tracts identified therein, which Plan consists of an agreement entitled, "Unit Agreement, Siberian Unit, Marion and Seneca Townships, Noble and Monroe Counties, Ohio," dated May 13, 2014 (the "Unit Agreement"); and an agreement entitled, "Operating Agreement," also regarding the Siberian Unit and of like date (the "Unit Operating Agreement"); and,

WHEREAS, the undersigned is the owner of a Working Interest in and to one or more of the Tracts identified in said Unit Plan, namely, the Tracts identified below (hereinafter, the "Owner").

NOW, THEREFORE, the Owner hereby approves the Unit Plan and acknowledges receipt of full and true copies of both the Unit Agreement and the Unit Operating Agreement.

IN WITNESS WHEREOF, the undersigned has executed this instrument on the date set forth opposite the signature of its representative.

WORKING INTEREST OWNER

TRACT NO. (see attached)

TRACT ACREAGE 702.181

RELATED WORKING INTEREST PERCENTAGE 99.99089%

Antero Resources Corporation

Date 9/3/14

By: Brian A. Kuhn SF
Name: Brian A. Kuhn
Title: Vice President - Land

Exhibit 5

| Tract | Owner | Parcel | Acreage |
|---|---|---|---|
| 1 | The Pond Minerals, LLC | 23-21148.001 | 8.099 |
| 2 | Bowen Land Minerals, LLC | 23-21139.001 | 0.217 |
| 3 | The Pond Minerals, LLC | 20-10015.000 | 2.394 |
| 4 | The Pond Minerals, LLC | 20-10014.000 | 0.174 |
| 5 | The Pond Minerals, LLC | 20-17023.000 | 0.716 |
| 6 | The Pond Minerals, LLC | 20-17022.000 | 0.930 |
| 7 | The Pond Minerals, LLC | 20-17021.000 | 1.167 |
| 8 | The Pond Minerals, LLC | 23-21148.002 | 4.766 |
| 9 | The Pond Minerals, LLC | 20-17024.000 | 4.281 |
| 10 | The Pond Minerals, LLC; Gary and Nancy Rubel | 23-21148.000 | 48.768 |
| 11 | The Pond Minerals, LLC | 20-17018.000 | 13.397 |
| 12 | Gary A. and Nancy S. Rubel | 20-17004.000 | 34.080 |
| 13 | Antero Resources Corporation | 23-21143.000 | 33.114 |
| 14 | Gary and Nancy Rubel | 20-17019.000 | 5.662 |
| 15 | Bryon D. and Joann Carpenter; Brandon and Kimberly Ward | 20-17017.000 | 2.028 |
| 16 | Michael and Patricia R. Campbell | 23-51118.000 | 23.619 |
| 17 | Gary A. and Nancy S. Rubel | 23-21144.000 | 29.816 |
| 18 | Gary A. and Nancy S. Rubel | 20-17025.000 | 10.350 |
| 19 | Wallace R. and Judy A. Carpenter | 20-17003.000 | 83.419 |
| 20 | Tammy M. Guy FKA Tammy M. Yocum | 20-17016.000 | 1.776 |
| 21 | Gary A. and Nancy S. Rubel | 23-21156.000 | 0.045 |
| 22 | Carson D. and Teresa L. Spence | 20-17003.100 | 66.702 |
| 23 | Ruby H. Heft | 20-17007.000 | 35.358 |
| 24 | Martha L. Cline | 20-17011.000 | 0.733 |
| 26 | Gary and Nancy Rubel | 21-18017.000 | 36.937 |
| 27 | Carson D. and Teresa L. Spence | 20-18001.000 | 41.835 |
| 29 | Ruby H. Heft | 20-18011.000 | 64.003 |
| 30 | Crist R. and Amanda L. Byler | 21-18006.000 | 15.762 |
| 31 | Steven R. McClain | 21-18014.000 | 74.354 |
| 32 | Amy M. Zwick | 21-18008.000 | 2.751 |
| 33 | Charles F. Yontz | 21-18004.000 | 43.821 |
| 34 | Charles F. Yontz | 20-18002.000 | 10.104 |
| 35 | Amy M. Zwick | 21-18016.000 | 0.777 |
| 36 | Charles F. Yontz et al | 20-19006.000 | 0.053 |
| 37 | Rockhill Acres, LLC | 21-18013.000 | 0.173 |
| | | **Total** | **702.181** |