Docket #0028 Date Filed: 9/24/2020

IN THE UNITED STATES BANKRUPTCY COURT
FOR THE DISTRICT OF DELAWARE

In re:	Chapter 11
EXTRACTION OIL & GAS, INC., *et al.*,[1]	Case No. 20-11548 (CSS)
Debtors.	(Jointly Administered)
EXTRACTION OIL & GAS, INC.,	
Plaintiff,	
v.	Adv. Proc. No. 20-50833 (CSS)
PLATTE RIVER MIDSTREAM, LLC AND DJ SOUTH GATHERING, LLC,	**RE: D.I. 21, 25**
Defendants.	

NOTICE OF FILING OF PROPOSED REDACTED VERSION OF PLATTE RIVER MIDSTREAM, LLC AND DJ SOUTH GATHERING, LLC'S RESPONSE IN OPPOSITION TO EXTRACTION OIL & GAS, INC.'S MOTION FOR SUMMARY JUDGMENT

PLEASE TAKE NOTICE that, on September 23, 2020, Platte River Midstream, LLC ("PRM"), and DJ South Gathering, LLC ("DJ South", and with PRM, the "Companies"), creditors and parties-in-interest in the above-captioned cases of the above-captioned debtors and debtors in possession (collectively, the "Debtors" or the "Plaintiffs") and defendants (individually, a "Defendant" and collectively, the "Defendants") in the above-captioned adversary proceeding

[1] The Debtors in these Chapter 11 Cases, along with the last four digits of each Debtor's federal tax identification number, are: MTE Holdings LLC (7894); MTE Partners LLC (1158); Olam Energy Resources I LLC (0770); MDC Energy LLC (9140); MDC Texas Operator LLC (1087); Ward I, LLC (6817); and MDC Reeves Energy LLC (3644). The Debtors' address is 280 East 96th Street, Suite 210, Indianapolis, Indiana 46240.

brought by the Debtors (the "Adversary Proceeding"), filed the *Motion to File Under Seal (A) Objection of DJ South Gathering, LLC, and of Platte River Midstream, LLC, to Debtors' Second Omnibus Motion for Entry of an Order (I) Authorizing Rejection of Unexpired Leases of Nonresidential Real Property and Executory Contracts Effective as of the Dates Specified Herein and (II) Granting Related Relief and (B) Platte River Midstream, LLC and DJ South Gathering, LLC's Response in Opposition to Extraction Oil & Gas, Inc.'s Motion for Summary Judgment* [Adv. D.I. 25] (the "Motion to Seal"),[2] seeking, among other relief, authority to file the Response Brief under seal.

PLEASE TAKE FURTHER NOTICE that, consistent with the relief requested in the Motion to Seal and pursuant to Local Rule 9018-1(d)(ii), the Companies hereby file the attached proposed redacted version of the Response Brief, attached hereto as **Exhibit 1**.

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[2] Capitalized terms not defined herein are used as in the Motion to Seal.

Dated: September 24, 2020
Wilmington, Delaware

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EXHIBIT 1

IN THE UNITED STATES BANKRUPTCY COURT
FOR THE DISTRICT OF DELAWARE

In re:	Chapter 11
EXTRACTION OIL & GAS, INC. *et al.*,[1]	Case No. 20-11548 (CSS)
Debtors.	(Jointly Administered)
EXTRACTION OIL & GAS, INC.,	
Plaintiff,	Adversary Proceeding
PLATTE RIVER MIDSTREAM, LLC AND DJ SOUTH GATHERING, LLC	Adv. Proc. No. 20-50833 (CSS)
Defendants.	

PLATTE RIVER MIDSTREAM, LLC AND DJ SOUTH GATHERING, LLC'S RESPONSE IN OPPOSITION TO EXTRACTION OIL & GAS, INC.'S MOTION FOR SUMMARY JUDGMENT[2]

[1] The Debtors in the Chapter 11 Cases, along with the last four digits of each Debtor's federal tax identification number, are: Extraction Oil & Gas, Inc. (3923); 7N, LLC (4912); 8 North, LLC (0904); Axis Exploration, LLC (8170); Extraction Finance Corp. (7117); Mountaintop Minerals, LLC (7256); Northwest Corridor Holdings, LLC (9353); Table Mountain Resources, LLC (5070); XOG Services, LLC (6915); and XTR Midstream, LLC (5624). The location of the Debtors' principal place of business is 370 17th Street, Suite 5300, Denver, Colorado 80202.

[2] The Companies submit a Declaration of Rogan McGillis, attached hereto as Exhibit BB, attesting to the authenticity of the Companies' business records referenced within and attached herewith.

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Exhibit AA Extraction Oil & Gas, Inc., Quarterly Report (Form 10-Q) at 11 (May 11, 2020)

Exhibit BB Authenticating Declaration of Rogan McGillis Regarding the Companies' Business Records (Sept. 18, 2020)

Platte River Midstream, LLC ("PRM") and DJ South Gathering, LLC ("DJ South") (together, the "Companies") hereby submit this Response in Opposition to Extraction Oil & Gas, Inc.'s ("Extraction's") Motion for Summary Judgment (the "Motion").

INTRODUCTION AND SUMMARY OF THE ARGUMENT

1. The Companies and Extraction are parties to two long-term contracts, pursuant to which the Companies have built, installed, and operated two underground crude oil pipeline systems. These systems were custom built to transport Extraction's crude oil from its wells located in several Colorado counties to downstream locations in Weld County, Colorado.

2. The Companies were created to build and operate the transportation systems for Extraction. Indeed, Extraction's affiliates owned interests in the Companies as joint ventures.

3. The Companies invested hundreds of millions of dollars in obtaining permits, securing real property interests, installing underground pipelines, and otherwise ensuring that Extraction can transport its current and future production by pipeline in urban areas north of Denver. In return, Extraction dedicated all of its crude oil interests within certain defined areas, whether produced or in the ground, to be delivered into the Companies' pipelines for the durations of the agreements. Without the dedications, the pipelines would not have been built.

4. Extraction has filed an adversary proceeding seeking declarations that the agreements do not create covenants running with the land, and therefore can be rejected as executory contracts. *See* Adversary Compl. [Dkt. #1] at ¶¶ 31-49. Extraction immediately moved for summary judgment based solely on the agreements' language. *See* Mot. at 1, 8-9.

5. Under Colorado law, a contract creates a covenant running with the land when (1) the parties intend to create this covenant, and (2) the underlying agreement touches and concerns the land. *See Reishus v. Bullmasters, LLC*, 409 P.3d 435, 440 (Colo. App. 2016). Based on this standard, summary judgment should be denied for multiple reasons:

First, Extraction's argument ignores numerous provisions in the parties' agreements that demonstrate the parties' intent to create covenants running with the land, and that the agreements touch and concern the land. When the agreements are read as a whole, Extraction's Motion should be denied. *See Reishus*, 409 P.3d at 441 ("[W]e do not read individual provisions in isolation when deciding whether a covenant is real or personal; instead, we look at the covenant as a whole.").

Second, the agreements must be considered in light of the factual circumstances surrounding the parties' intent and the agreements' relationship to the property, all of which present factual issues Extraction ignores. *See Lookout Mtn. Paradise Hills Homeowners' Ass'n v. Viewpoint Assocs.*, 867 P.2d 70, 73-76 (Colo. App. 1993) (evaluating agreement to determine whether covenant ran with the land). This is particularly relevant to other contracts and assignments confirming the parties' intent. *See infra* at ¶ 21, Sec. I; *see also Meredith v. Ramsdell*, 384 P.2d 941, 944 (Colo. 1963) ("It is elementary that an agreement may be evidenced by several writings, which, when connected, show the parties, subject matter, terms, and consideration. Such concept has been applied to oil and gas contracts.") (citations omitted).

Third, Extraction insists on imposing legal elements for covenants running with the land that do not exist under Colorado law, s*ee* Mot. at 13-27, such as horizontal privity or a specific "legal relationship" to create a covenant. *See Reishus*, 409 P.3d at 441.

Fourth, at a minimum, the contracts are ambiguous. *See Cheyenne Mtn. Sch. Dist. No. 12 v. Thompson*, 861 P.2d 711, 715 (Colo. 1993) (holding contract "is ambiguous when it is reasonably susceptible to more than one meaning") (citation and internal quotations omitted). The parties' intent must be considered based on the facts surrounding (i) the parties' reasons for entering into the contracts, (ii) their negotiations, (iii) their contractual obligations, and (iv) their

performance under the contracts. *See infra* Sec. I (identifying facts describing these circumstances). These issues cannot be resolved on summary judgment.

STATEMENT OF FACTS

6. Extraction relies only on its interpretation of the parties' contracts. *See* Mot. at 3-7. Its interpretation is argument, not evidence. *See Finjan, Inc. v. Symantec Corp.*, 2013 WL 5302560, at *25 (D. Del. Sept. 19, 2013) ("It is well established that attorney argument does not constitute evidence.") (citations omitted). Its interpretation also is incomplete and inaccurate. The relevant contractual terms, and the relevant facts, are presented below.

The Companies and In-Field Transportation Systems

7. ARB Midstream, LLC ("ARB") is the manager and majority owner of the Companies. *See* Declaration of Rogan McGillis, attached as Exhibit A at ¶¶ 24(a), 31. ARB builds and operates pipeline systems to transport oil and other liquid hydrocarbons. *See id.* at ¶ 4. These are known as "in-field systems," because they transport oil within the specific production area, as opposed to larger pipelines that transport production over long distances. *See id.*

8. Building an in-field system requires the installation of dozens, even hundreds, of miles of pipelines buried several feet underground, which in turn requires ARB to obtain rights of ways or easements from property owners, purchase surface lands for facilities, and obtain permits from local and state governments. *See id.* at ¶ 6. Producers also must grant access to their surface and mineral estates to connect the transportation pipelines. *See id.*

9. In-field systems require a substantial upfront financial investment, because the pipelines must be installed before they can deliver production. *See id.* at ¶ 7. Buying rights of ways, easements, surfaces locations, purchasing and building a network of steel pipelines, and installing other facilities costs many millions of dollars. *See id*. That investment is recovered years later through the producer's payment of monthly charges. *See id*.

10. To justify the upfront investment, transportation companies commonly require producers to dedicate their acreage to the pipelines for the term of the agreement. *See id.* at ¶ 8. The language of a dedication can vary, but the intent is the same: to ensure the producer delivers production into the pipelines so the transportation company recovers the cost of installing an in-field system. *See id.* at ¶ 12. Without the dedication, which binds the producer and its successors, in-field systems would not obtain financing and could not be economically built. *See id.* at ¶ 10.

11. A dedicated pipeline system creates substantial value for producers. *See id.* at ¶ 13. Access to a dedicated system ensures that production will be transported to market for sale. *See id*. Mineral leaseholds with dedicated transportation generally are more valuable than leaseholds without such dedications. *See id*.

12. Pipelines are particularly important in populated areas, such as the Denver-Julesburg Basin, a production area north of Denver, Colorado (the "DJ Basin"). *See id.* at ¶ 14. Without pipelines, the producer's only alternative is to use tanker trucks to transport its crude oil. *See id*. Tanker trucks are noisy, increase traffic, and transport a hazardous product on Colorado's roads. *See id*. Residents of towns such as Greeley, Broomfield, and Aurora have opposed oil and gas production unless the producer agrees to use pipelines instead of trucks. *See id.* at ¶ 15. Some communities have required producers to use pipelines. *See id*. at ¶¶ 14-15.

Platte River Midstream and Its Transportation Agreement with Extraction

13. In September 2016, ARB acquired PRM as a platform to build and operate a crude oil transportation system in Larimer and Weld Counties, Colorado (the "PRM Transportation System"). *See id*. at ¶ 16.

14. In late 2016, Extraction began negotiating with ARB to expand the PRM Transportation System to connect to Extraction's current and planned wells in Larimer and Weld Counties. *See id*. at ¶ 18. During negotiations, Extraction explained its aggressive drilling

program, and therefore needed a transportation company with the resources and commitment necessary to quickly connect to Extraction's planned new wells. *See id*. at ¶ 19. Extraction also expressed its desire for a long-term relationship with its transportation company, and sought to form a joint venture as the best way to ensure this long-term relationship. *See id*. at ¶ 22.

15. At the time, Extraction owned and operated its own transportation company, XTR Midstream, LLC ("XTRM"). *See id.* at ¶ 21. [redacted] *See id*. [redacted] *See id*.

16. Extraction also was interested in obtaining pipeline service to a large drilling project located west of Greeley, Colorado, near a community known as Triple Creek. *See id.* at ¶ 20. The project called for 22 wells, and was a significant opportunity for Extraction. *See id*. It also was the source of significant controversy among residents of Triple Creek, who opposed Extraction's plan to use tanker trucks. *See id*. Residents sued the Colorado Oil and Gas Conservation Commission (the "COGCC") after it approved Extraction's plan to use trucks, and a state court found the COGCC acted arbitrarily in approving Extraction's plans. *See* Order, *Neighbors Affected by Triple Creek v. COGCC*, 2016-cv-34274 (Denver Dist. Ct. Aug. 23, 2017), attached as Exhibit B. In particular, the court found Extraction repeatedly told residents and civic leaders that it would use pipelines. *See id.* at 6.

17. The PRM Transportation System was the solution to Extraction's transportation problems. *See* Exhibit A at ¶¶ 19-22; [redacted] It was evident to ARB during negotiations that Extraction

needed pipelines for its wells in Triple Creek and the northern production area. *See* Exhibit A at ¶ 20. A committed pipeline would allow Extraction to drill new wells in a populated area and lessen community resistance. *See id.* at ¶¶19-20; *see also* Extraction Press Release "An Oil Pipeline Solution" (May 22, 2017), attached as Exhibit D. Extraction thus had no plans to build infrastructure to transport oil with trucks at each well site. *See* Exhibit A at ¶ 21.

18. For its part, PRM required a dedication of Extraction's interests in a defined area to justify entering the contract and investing in the installation and operation of the pipeline system. *See id.* at ¶ 23. Without receiving that dedication, which PRM intended to be part of Extraction's transportation agreement, it would not have installed the pipeline system. *See id*. In exchange for the dedication, Extraction wanted equity in the pipeline system with the potential to acquire the system later on [redacted] *See id.* at ¶¶ 23, 24(b); [redacted]

19. By agreeing to contract with PRM to provide transportation services, Extraction no longer needed to operate its own transportation company, XTRM. *See* Exhibit A at ¶ 22. [redacted] *See id.*

20. Because Extraction would not have direct control over its transportation provider, Extraction insisted on creating a joint venture that would own PRM, providing Extraction with an equity stake in the transportation system and a voice in PRM's management. *See id*.

21. On April 14, 2017, the parties entered into four agreements:

First, ARB and XTRM entered into a First Amended and Restated Limited Liability Company Agreement (the "LLC Agreement"), and formed Platte River Holdings, LLC ("PRH"). *See* LLC Agreement, attached as Exhibit F. PRH would wholly own PRM, [redacted]

[redacted] The parties further agreed any business opportunities within the AMI would be shared between ARB and Extraction's affiliate. *See id.* at § 6.9(b). The LLC Agreement also limited the parties' ability to assign their interests in PRH. *See id.* at §§ 5, 10.

Second, Extraction and PRM agreed to the First Amended and Restated Transportation Services Agreement (the "PRM TSA"). *See* Exhibit A to Mot.

Third, XTRM and PRH entered into a Contribution Agreement whereby [redacted] *See* Contribution Agreement between ARB Platte River, LLC, XTR Midstream, LLC and Platte River Holdings, LLC (Apr. 14, 2017), attached as Exhibit G.

Fourth, [redacted] *See* Exhibit A at ¶ 24(d); [redacted].

22. The PRM TSA contemplated Extraction would dedicate its working interests in specific property to PRM for at least ten years (the "PRM Dedication Area"). *See id.* at § 4.1; *see also* Mot. at 3. [redacted] *See* Exhibit A at ¶ 23. [redacted] *See id.* at ¶ 24(b); *see also* Exhibit E. XTRM would not have received this grant of equity absent the dedication of Extraction's interests. *See id.*

23. Pursuant to the PRM TSA, [redacted] Exhibit A to Mot. at §§ 1.1(bb) (emphasis added), 2.1. The dedicated "Interests" also include all of Extraction's [redacted] The PRM Dedication Area includes certain locations in Larimer and Weld Counties, and was identified in the LLC Agreement. *See id.* at § 1.1(t); *see also* Exhibit F at § 10 ([redacted]).

24. The dedication was intended to cover, and drafted to cover, all of Extraction's crude oil interests in the ground within the PRM Dedication Area. *See* Exhibit A to Mot. at §§ 1.1(bb), 2.1; *see also* Exhibit A at ¶¶ 23, 24(b). Accordingly, the dedication identifies the real property interests burdened by the dedication. *See* Exhibit A to Mot. at § 1.1(t) (defining "Dedication Area" by legal description). After closing, [redacted]

25. To date, PRM has spent [redacted] *See* Exhibit A at ¶ 25; [redacted]

26. The PRM Transportation System is a custom system that is directly connected to each of Extraction's well pads within the PRM Dedication Area. *See* Exhibit A to Mot. at § 2.4. and Exh. B; *see also* Exhibit A at ¶ 26; [redacted] This requires

Extraction to prepare each well pad for connection to the pipeline, and for PRM to install well-specific connections at each well pad. *See* Exhibit A to Mot. at § 2.4. and Exh. B; *see also* Exhibit A at ¶ 26. In addition to the Assignment of Easements from XTRM, Extraction has executed right of way agreements for its additional well pads, which were granted in connection with, and in furtherance of, the PRM TSA and were recorded with the counties' records. *See* Exhibit A at ¶ 26; [redacted]

27. Because it committed to using the PRM Transportation System to transport its production, Extraction is limited in its ability to use alternative means to transport its crude oil within the PRM Dedication Area. [redacted]

28. The PRM TSA expressly states it [redacted] and restricts the assignment of the contract without the other party's consent. Exhibit A to Mot. at § 13.9.

DJ South Gathering and Its Transportation Agreement with Extraction

29. In October 2017, Extraction and ARB began negotiations on a new pipeline system to transport Extraction's crude oil produced from wells in five Colorado counties (the "DJ South Transportation System"). *See* Exhibit A at ¶ 29. Unlike the PRM Transportation System, which is directly connected to Extraction's wells, the DJ South Transportation System would connect to central facilities that collect production from multiple wells. *See id.* at ¶ 35. Because the new system was not directly connected to Extraction's well sites, it was important to ARB that the new contract expressly reflect the parties' intent to create a covenant running with the land. *See id.* at ¶ 36. Extraction did not disagree with this language. *See id.*

30. On January 17, 2018, ARB formed a new company, DJ South, to build and operate the new transportation system. *See id.* at ¶ 31. DJ South is wholly owned by PRH, which in turn was owned by ARB and Extraction's affiliate. *See id.*

31. On May 16, 2018, XTRM assigned all of its rights and interest under the LLC Agreement to Elevation Midstream, LLC ("Elevation"), pursuant to a Joinder and First Amendment to the LLC Agreement (the "LLC Amendment"). [redacted] At the time of the assignment, Elevation was a wholly owned subsidiary of Extraction.[3] *See* Extraction Press Release, announcing "South DJ Basin Midstream Solution" (July 9, 2018), attached as Exhibit O (identifying Elevation as a "wholly-owned subsidiary"). [redacted]

32. Also, on the same day, Extraction and DJ South entered into the Transportation Services Agreement dated May 16, 2018 (the "DJ South TSA"). *See* Exhibit B to Mot; [redacted] The PRM TSA and the DJ South TSA are together referred to as the "TSAs." [redacted] *See* Exhibit A at ¶ 33(a)-(b).

33. Pursuant to the DJ South TSA, Extraction [redacted]

[3] Beginning July 3, 2018, Elevation entered into a series of securities purchase agreements with GSO Capital Partners Lp. As a result, Extraction lost voting control of Elevation during the first quarter of 2020. *See* Extraction Oil & Gas, Inc., Quarterly Report (Form 10-Q) at 11 (May 11, 2020), attached as Exhibit AA.

[redacted] The DJ South Dedication Area is defined to include certain locations in five Colorado counties. *See id.* at § 1.1(u). As with the PRM TSA, DJ South would not have entered into the DJ South TSA without the dedication of Extraction's interests. *See* Exhibit A at ¶¶ 32, 33(b). In exchange for Extraction's dedication of all of its interests within the DJ South Dedication Area, [redacted]

34. The DJ South TSA contemplated that Extraction would dedicate its interests in the DJ South Dedication Area for at least ten years. *See* Exhibit B to Mot. at § 5.1; *see also* Mot. at 3. This intent was reflected in the additional equity Elevation (and Extraction) acquired in exchange for the dedication. *See* Exhibit A at ¶ 33(b); [redacted] Elevation (and Extraction) would not have received equity absent the dedication of its interests within the DJ South Dedication Area. *See* Exhibit A at ¶ 33(b).

35. To avoid any doubt as to the irrevocable nature of Extraction's commitment, the parties agreed that [redacted]

36. The DJ South dedication was intended to cover, and was drafted to cover, all of Extraction's crude oil interests in the ground within the DJ South Dedication Area. *See id.* at §§ 1.1(dd), 2.1 [redacted] The dedication specifically identifies the real property

subject to the dedication. *See id.* at § 1.1(u) (defining Dedication Area by legal description). [redacted]

37. Extraction executed a "Memorandum of Dedication" that was recorded in the county real property records, as required by the DJ South TSA. *See* Exhibit B to Mot. at § 2.5 (requiring recording); *see also* Memoranda of Dedication, attached as Exhibit Q.

38. Further tying the dedication to Extraction's real property interests, the DJ South TSA restricts Extraction's ability to sell or transfer certain acreage within the DJ South Dedication Area without obtaining a release of that acreage from DJ South. *See* Exhibit B to Mot. at § 2.6.

39. [redacted] The PRM Transportation System and DJ South Transportation System are referred to together as the "Transportation Systems."

40. [redacted]

41. [redacted]

[redacted]

42. [redacted] Extraction is subject to an agreement with Broomfield that requires the use of pipelines to transport its production. *See* Resolution No. 2017-186, attached as Exhibit T. [redacted]

Compensation Under the TSAs

43. The Companies recover a portion of their upfront investments, along with a return on those investments, in several ways. First, Extraction is required to pay the Companies a monthly tariff approved by FERC for the volumes it delivers into the Transportation Systems. *See* Exhibit A to Mot. at § 5.1; Exhibit B to Mot. at § 6.1. Second, Extraction is obligated to make a fixed monthly payment to the Companies, regardless of the volumes it delivers. *See* Exhibit A to Mot. at § 6.1; Exhibit B to Mot. at § 7.1. The fixed monthly payment sets a minimum that the Companies will be paid, although it is offset, and usually exceeded, by tariff payments. *See* Exhibit A to Mot. at § 6.1; Exhibit B to Mot. at § 7.1. Third, the fixed monthly payment represents the monthly amount of the contractually defined "total financial commitment" that Extraction agreed to pay the Companies. *See* Exhibit A to Mot. at § 6.2; Exhibit B to Mot. at § 7.2.

44. [redacted]

45. The "total financial commitments" do not reflect the value of Extraction's commitment to transport all of its dedicated production using the Transportation Systems. *See* Mot. at 4-5; *see also* Exhibit A at ¶¶ 8-9, 40-43. The value of Extraction's dedications is much greater than the "total financial commitments," [redacted]

[redacted] The "total financial commitments" simply are intended to service and secure the debt financing associated with constructing the Transportation Systems, not to reflect their value to PRM and DJ South. *See* Exhibit A ¶¶ 8-9, 40-43.

LEGAL STANDARD

46. Summary judgment is inappropriate unless "the pleadings, the discovery and disclosure materials on file, and any affidavits show that there is no genuine issue as to any material fact and that the movant is entitled to judgment as a matter of law." *In re Maxus Energy Corp.*, 615 B.R. 62, 68 (Bankr. D. Del. 2020) (quoting *Celotex Corp. v. Catrett*, 477 U.S. 317, 322 (1986)). Extraction "bears the burden of proving that no genuine issue of material fact exists." *In re Quintas Corp.*, 397 B.R. 710, 714 (Bankr. D. Del. 2008) (citation omitted). The Companies' evidence is accepted as true, and all reasonable inferences are drawn in the Companies' favor and against summary judgment. *See In re LTC Holdings, Inc.*, 597 B.R. 554, 559 (Bankr. D. Del. 2019) (citing *Anderson v. Liberty Lobby, Inc.*, 477 U.S. 242, 255 (1986)).

ARGUMENT

47. Under Colorado law, only two elements are required to "create a real covenant, the parties must intend for the covenant to run with the land and bind successors in interest, and the covenant must 'touch and concern' the land." *Reishus*, 409 P.3d at 440 (citing *Cloud v. Ass'n of Owners*, 857 P.2d 435, 440 (Colo. App. 1992)).

48. These factors are different from those interpreted in *Sabine Oil & Gas Corp. v. HPIP Gonzales Holdings, LLC* (*In re Sabine Oil & Gas Corp.*), 550 B.R. 59 (Bankr. S.D.N.Y. 2016). In *Sabine*, the court held Texas law requires privity of estate and a conveyance of real property to create a covenant running with the land. *See id.* at 67-70. As discussed in Section III

below, privity and conveyance are not required under Colorado law, and in any event, the agreements at issue in *Sabine* are not the same as the TSAs here. *Sabine* has never been cited by a Colorado court on any issue, let alone whether contracts create covenants running with the land.

49. Under Colorado law, the factual record unquestionably could lead a "a reasonable jury… [to] return a verdict" for the Companies that the TSAs create covenants running with the land and bind Extraction's successors. *Anderson*, 477 U.S. at 248; *see Lookout*, 867 P.2d at 73-76 (considering facts surrounding creation of covenant under Colorado law). At a minimum, the complete factual record is required to determine whether the TSAs create covenants running with the land. *See Centennial-Aspen II Ltd. P'ship v. City of Aspen*, 852 F. Supp. 1486, 1492 (D. Colo. 1994). Extraction's Motion should be denied.

I. The Facts Demonstrate the Parties' Intent to Create Covenants Running With the Land Under Colorado Law.

50. To create a covenant running with the land, "the parties must intend for the covenant to run with the land and bind successors in interest." *Reishus*, 409 P.3d at 440. The parties' intent is determined by considering the agreements "as a whole, keeping in mind their underlying purpose." *B.B. & C. P'ship v. Edelweiss Condominium Ass'n*, 218 P.3d 310, 315 (Colo. 2009) (citation and internal quotations omitted); *see also Reishus*, 409 P.3d at 441 ("[W]e do not read individual provisions in isolation when deciding whether a covenant is real or personal; instead, we look at the covenant as a whole.").

51. Extraction concedes the DJ South TSA was intended to create a covenant running with the land burdening Extraction's real property interests in the DJ South Dedication Area. *See* Mot. at 6-7, 10-11; [redacted]

[redacted] Intent, therefore, is established for the DJ South TSA. *See Monarch Midstream, LLC v. Badlands Prod. Co. (In re Badlands Energy, Inc.)*, 608 B.R. 854, 870 (Bankr. D. Colo. 2019) ("Under … Colorado law, an express statement in the document creating the covenant that the parties intend to create a covenant running with the land is usually dispositive of the intent issue.") (citations and internal quotations omitted); *see also Cloud*, 857 P.2d at 440 (express language demonstrated intent).

A. The PRM TSA Demonstrates Intent.

52. The PRM TSA also establishes a covenant running with the land burdening Extraction's interests in the PRM Dedication Area. *See Reishus*, 409 P.3d at 440. Extraction argues that the absence of express language in the PRM TSA evidences the parties' lack of intent. *See* Mot. at 11-12. As Extraction recognizes, however, "no magic words are necessary" to create a covenant running with the land. Mot. at 11; *see also TBI Expl. v. Belco Energy Corp.*, 2000 WL 960047, at *4 (5th Cir. June 14, 2000) ("Our survey of Colorado case law has not revealed any precedent …that a covenant running with the land must be expressed in specific or magical terms."). No Colorado court has required express language, or held the lack of express language is dispositive. Rather, Colorado courts look at contracts "as a whole…, giving effect to all provisions contained therein." *Lookout Mtn.*, 867 P.2d at 75 (citation omitted).

53. Under the PRM TSA, [redacted] Contrary to Extraction's contention, *see* Mot. at 4-6, 23-24, [redacted]

[redacted]

54. In *Badlands*, the court determined a covenant encompassed both extracted and unextracted minerals because it dedicated "the interest of Producer in all Gas reserves in and under" a specific geographic area. 608 B.R. at 869 (emphasis added). Contrary to Extraction's arguments, *see* Mot. at 4-6, 23-24, the PRM TSA's dedication similarly references and applies to Extraction's mineral interests "under" the ground, not only production from the wells. *See* Exhibit A to Mot. at §§ 1.1(bb), 2.1; *see also Bill Barrett Corp. v. Lembke*, 2018 WL 4225030, at *5 (Colo. App. Sept. 6, 2018) (real property includes non-extracted minerals) (citation omitted).

55. Underscoring its burden on real property, [redacted] This evidences the parties' intent to create a covenant running with the land. *See, e.g.*, *Alta Mesa Res., Inc. v. Kingfisher Midsteam, LLC (In re Alta Mesa Res., Inc.)*, 613 B.R. 90, 99-100 (Bankr. S.D. Tex. 2019) (covenant including "After-Acquired Interests" in the dedication ran with the land). The parties did not limit the dedication of interests to current production. *See, e.g.*, *Badlands*, 608 B.R. at 869 (contrasting dedication in *Sabine* that included only gas "produced and saved" from the area) (citing *Sabine*, 550 B.R. at 66).

56. The PRM TSA [redacted] Extraction's interests in its wells is derived from its leasehold mineral interests, *i.e.*, real property. *See Maralex Res., Inc. v. Chamberlain*, 320 P.3d 399, 403 (Colo. App. 2014)

("[A]n oil and gas lessee has an interest in real property"); *Hagood v. Heckers*, 513 P.2d 208, 214 (Colo. 1973) (a lessee's interest in oil and gas leases is real property). Extraction's dedication of its interests demonstrates its intent to create a covenant running with the land.

57. The PRM TSA also identifies the dedicated interests by a legal description of the real property, not simply by "production," as Extraction suggests. *See* Mot. at 17-18, 24. Specifically, the PRM Dedication Area is defined as four specific Townships in Larimer and Weld Counties. Exhibit A to Mot. at § 1.1(t). This is a legal description of real property, not production. *See Griffin v. United Bank of Denver*, 599 P.2d 866, 868 (Colo. 1979) ("[A] complete legal description of real estate constitutes a clear and accurate identification of the property.") (citations omitted); *see also Badlands*, 608 B.R. at 869 (contrasting dedication in *Sabine* that was limited to gas "produced and saved … from wells … located within the Dedicated Area") (quoting *In re Sabine Oil & Gas Corp.*, 567 B.R. 869, 872 (S.D.N.Y. 2017)) (emphasis added).

58. To avoid any doubt about the continuing nature of the PRM TSA, Section 13.9 expressly provides *all* of the agreement [redacted] The parties also [redacted] *Id.*; *see also Badlands*, 608 B.R. at 870 (restriction on assignment was suggestive of intent to bind successors and assigns).

59. The LLC Agreement between ARB and Extraction's affiliate underscores the parties' intent. PRH was formed expressly to own, operate, develop, and expand PRM's crude oil gathering facilities and related infrastructure. *See* Exhibit F at § 1.6. Extraction's affiliate and ARB agreed that they would share any business opportunity within the geographic area defined by the LLC Agreement. *See id.* at § 6.9(b). The agreement also restricted ARB and XTRM from

assigning their interests in PRH absent certain conditions. *See id.* at § 5.1. These restrictions on assignment were the demands of Extraction, which wanted express contractual assurances it could control the identity of the party installing and operating the PRM Transportation System. *See* Exhibit A at ¶ 28. Extraction cannot now avoid its intent to bind successors and assigns.

60. The express provisions in the PRM TSA demonstrate both parties' intent to create a covenant running with the land, and they must be read as a whole. In *Cloud*, the Colorado Court of Appeals determined a covenant ran with the land by reading the agreement's provisions as a whole, not in isolation. *See* 857 P.2d at 440; *see also Reishus*, 409 P.3d at 441 ("[W]e do not read individual provisions in isolation when deciding whether a covenant is real or personal; instead, we look at the covenant as a whole."). The PRM TSA must be interpreted the same way.

B. The Purpose and Surrounding Circumstances of the PRM TSA Demonstrate the Parties' Intent to Create a Covenant Running With the Land.

61. Under Colorado law, courts consider whether the parties intended to create a covenant running with the land based on the contract's purpose. *See Reishus*, 409 P.3d at 435. In *Reishus*, for example, the court found an ownership agreement ran with the land where its purpose was "to have an agricultural property that would also provide a quality hunting experience." *Id.* at 441 (citations and internal quotations omitted). The PRM TSA reveals the same purpose to create a covenant running with the land.

62. [redacted]

Residents complained about Extraction's use of trucks to transport production, and sued the COGCC for allowing Extraction to move forward with drilling in Triple Creek without a pipeline commitment. *See* Exhibit B. A state court observed that Extraction's use of trucks conflicted with its assurances to city officials and residents that it would use pipelines. *See id.* [redacted]

[redacted]

After entering into the PRM TSA, Extraction issued a press release touting the PRM Transportation System as "a dedicated oil pipeline would be used to transport oil produced at Triple Creek." Exhibit D (emphasis added). [redacted]

63. [redacted] Its intent to create a covenant tied to the land, therefore, is clear from its indisputable conduct. *See Reishus*, 409 P.3d at 435-41.

64. PRM, in turn, had a clear purpose of securing a covenant running with the land when entering the PRM TSA. Specifically, PRM required a dedication of Extraction's interests in a defined area in order to justify entering the contract and investing in the installation and operation of the pipeline system. *See* Exhibit A at ¶ 23. Without receiving that dedication, which PRM intended to be part of Extraction's transportation agreement, it would not have installed the pipeline system. *See id*. This is not unusual in the industry, because the dedication assures the midstream company it will obtain financing to build the system. *See id.* at ¶¶ 10, 12.

65. ARB issued a press release corroborating its purpose, stating it had secured a dedication from Extraction for all "existing and all future wells." ARB Press Release, announcing

"Large Production Dedication in Colorado's Niobrara Play" (July 13, 2007), attached as Exhibit Y. PRM constructed 95 miles of pipeline to transport Extraction's production downstream. *See* Exhibit A at ¶ 25. The PRM Transportation System is custom built, and physically connected to each well pad on Extraction's leasehold. *See id.* at ¶ 26; [redacted]

66. The parties' intent to create a covenant that would bind their successors and assigns, is demonstrated by their purpose in entering into the PRM TSA. *See Reishus*, 409 P.3d at 435 (determining covenant ran with the land based on purpose of the parties); *Lookout Mtn.*, 867 P.2d at 75 (construing covenants "as a whole" and "in view of their underlying purposes").

67. The facts also explain why the PRM TSA does *not* expressly state that it creates a covenant running with the land. Unlike the PRM Transportation System, which is directly connected to Extraction's wells on its leaseholds, the DJ South Transportation System receives Extraction's crude oil through CGFs located away from Extraction's wells. Because the DJ South Transportation System was configured differently, [redacted]

68. At a minimum, the foregoing facts demonstrate the PRM TSA can be found to be "ambiguous," that is, "reasonably susceptible to more than one meaning." *Cheyenne Mtn. Sch Dist. No. 12*, 861 P.2d at 715 ("Silence does create ambiguity … when it involves a matter naturally within the scope of the contract."). The Court must consider all facts surrounding the contract's formation and performance to ascertain intent. *See Centennial-Aspen II Ltd. P'ship*, 852 F. Supp.

at 1492. Given the facts set forth above, "a reasonable jury" could "return a verdict" for the Companies that the PRM TSA was intended to create a covenant running with the land. *Anderson*, 477 U.S. at 248. Summary judgment should be denied.

II. The TSAs Touch and Concern the Land.

69. Under Colorado law, "[a] covenant touches and concerns the land if it 'closely relates to the land, its use, or its enjoyment.'" *Reishus*, 409 P.3d at 440 (quoting *Cloud*, 857 P.2d at 440). The "'touch and concern' requirement is fulfilled when the covenant operates to benefit the physical use of the land." *Bigelow v. Nottingham*, 833 P.2d 764 (Colo. App. 1991), *rev'd in part on other grounds, Haberl v. Bigelow*, 855 P.2d 1368 (Colo. 1993); *see also Lookout Mtn.*, 867 P.2d at 75 (holding building restriction created covenant running with the land where benefits and burdens were closely related to property's use and enjoyment). Whether a covenant closely relates to the land must be "viewed in the context of [the agreement's] purpose." *Badlands*, 608 B.R. at 868 (contract must "be of such character that its performance or nonperformance will so affect the use, value or enjoyment of the land itself"). This is an inherently factual analysis.

70. Applying a similar principle, the court in *Alta Mesa* held natural gas gathering agreements contained covenants running with the land, because they furthered the purpose of the producer's mineral leases. 613 B.R. at 96, 102. "[A]n oil and gas lease creates an interest in land to search for and reduce to possession such [oil] as might be found beneath the land," and therefore "[a]ll of the property interests associated with an oil and gas lease," including the interests for production and marketing "are necessary for the lessee to successfully explore and produce his reserves." *Id.* at 102-03 (citation and internal quotations omitted). Not only did the gathering systems enhance the value of produced natural gas, but they enhanced the producer's unproduced reserves by reducing transportation costs for future production. *Id.* at 103-04.

71. Similarly, in *Badlands*, the court determined a production dedication touched and concerned the land under Utah law. 608 B.R. at 869. The court explained because the "dedicated reserves" under the gathering agreement were defined broadly to include "the interest of Producer in all Gas reserves in and under" the dedicated area, the gathering agreement encompassed real property. *Id.* (emphasis in original). As in Utah, "real property" under Colorado law includes non-extracted minerals. *See Bill Barrett Corp.*, 2018 WL 4225030, at *5 (citation omitted).

72. The TSAs touch and concern Extraction's real property interests because they directly benefit, and burden, Extraction's interests within the Dedication Areas. Extraction's mineral interests benefit from the Companies' obligation to construct permanent underground pipeline systems and related infrastructure capable of transporting Extraction's crude oil produced from the Dedication Areas. *See* Exhibit A to Mot. at §§ 1.1(nn), 2.4 and Exh. A; Exhibit B to Mot. at §§ 3.1. This provides direct, immediate value to Extraction's mineral estate by ensuring its production can access downstream markets. *See Alta Mesa*, 613 B.R. at 103-04 (benefit of dedicated transportation created covenant running with the land); *see also* Exhibit A at ¶ 13.

73. The TSAs particularly benefit Extraction's drilling program in urban areas near Denver. [redacted]

74. [redacted]

[redacted] This limits Extraction's "right to determine what happens to the [dedicated Interests] once it drills." *Alta Mesa*, 613 B.R. at 104. Extraction "commit[ed] itself to the gathering agreements," and "gave up its right to pursue other gathering strategies." *Id*.

75. The TSAs also restrict Extraction's use of real property. To connect its wells to the PRM Transportation System, Extraction granted easements to PRM to access the leasehold. *See* Exhibit A at ¶¶ 24(d), 26; [redacted] These agreements "carve out a portion of [Extraction's] lease easements and grant those portions to [the Companies]." *Alta Mesa*, 613 B.R. at 104.

76. Under the DJ South TSA, Extraction cannot transfer certain acreage within the DJ South Dedication Area without first obtaining DJ South's release. *See* Exhibit B to Mot. at § 2.6. This closely relates to Extraction's "land, its use, or its enjoyment." *Cloud*, 857 P.2d at 440. The DJ South TSA also required Extraction to execute Memoranda of Dedication, which were recorded in the county real property records. *See* Exhibit B to Mot at § 2.5; [redacted] These Memoranda reaffirm that the DJ South TSA affects and closely relates to Extraction's real property interests. *See* C.R.S. § 38-35-108 (recording necessary to put successors and assigns on notice).

77. The TSAs do much more than "affect only personal property," as Extraction contends. Mot. at 24. Rather, the TSAs are closely related to Extraction's use, possession, and enjoyment of real property, and thus touch and concern the land. *See Reishus*, 409 P.3d at 441; *see also Alta Mesa*, 613 B.R. at 104. Extraction's Motion should be denied.

III. Extraction's Attempt to Add New Legal Factors to Colorado Law Is Unavailing.

78. Faced with unfavorable facts on the two applicable elements of Colorado law, Extraction tries to impose additional, *inapplicable* legal requirements. *First*, Extraction argues it

can somehow satisfy its obligations with money damages, and therefore the TSAs do not touch and concern the land. *See* Mot. at 24-25. *Second,* Extraction claims a covenant running with the land requires a specific "legal relationship" akin to a formal conveyance. *See id.* at 21-22. *Third,* Extraction asserts horizontal privity is necessary to create a covenant running with the land. *See id.* at 13-20. As explained below, Extraction is wrong on all counts.

A. The "Total Financial Commitments" Do Not Eliminate the TSA's Covenants.

79. Both TSAs require Extraction to pay a "total financial commitment" over their terms. *See* Exhibit A to Mot. at §§ 1.1(ccc), 3.1; Exhibit B to Mot. at §§ 1.1(kkk), 4.1. [redacted]

80. Extraction argues that, because it can pay the remainder of the "total financial commitments" (notwithstanding its insolvency), the TSAs do not touch and concern the land. *See* Mot. at 24-25. Extraction cites no relevant Colorado authority to support this argument. *See id.*

81. *Badlands* considered a similar argument. *See* 608 B.R. at 868. There, the producer argued its gathering agreement created only a personal covenant, and did not burden real property, because it could pay the gatherer a deficiency payment in lieu of delivering gas. *See id.* Rejecting this argument, the court explained the payment was meant "to compensate [the gathering company] for the burdens associated with acquiring and operating the [gathering system]," but had no effect on the dedication or its covenant. *Id.* The same legal principle applies here, since payment of money cannot be divorced from the benefit to the mineral estate as a whole. *See, e.g.*, *Cloud,* 857 P.2d at 440 (covenant granting 10 percent of gross receipts as payment to developer ran with the land where remaining 90 percent benefitted homeowner association).

82. Extraction's argument concerning the "total financial commitments" is factually misplaced. The "total financial commitments" are not liquidated damages, and are simply one of several available remedies under the TSAs. *See* Exhibit A to Mot. at § 11.3; Exhibit B to Mot. at § 12.3. Nor are they intended to reflect the value of Extraction's dedications, which are much greater than the "total financial commitments." *See* Exhibit A at ¶¶ 8-9, 40-43. The purpose of the "total financial commitments" is to service the debt to build an in-field gathering system, [redacted] Extraction's argument should be rejected. *See Badlands*, 608 B.R. at 868.

B. Colorado Law Does Not Impose a "Legal Relationship" Test.

83. Extraction also urges the Court to consider whether the covenants created by the TSAs affect Extraction's "legal relationship to the land itself." Mot. at 21. Extraction claims this test is not satisfied, because produced crude oil is personal property, and the covenants do not affect Extraction's use of or legal right to the land. *See id.* at 21, 26-27.

84. Extraction's only support for the "legal relationship" test is a law review article written in 1914 by Harry Bigelow. *See* Mot. at 21 (citing Harry Bigelow, *The Content of Covenants in Leases*, 12 Mich. L. Rev. 639, 652 (1914)). While Extraction claims Colorado courts have "repeatedly cited Dean Bigelow's work with approval," *see* Mot. at 21 n.11, the "work" Extraction refers to is the Restatement (First) of Property, to which Dean Bigelow was a contributor. *See id.* No Colorado case relies upon, or even cites, Bigelow's 1914 article.

85. None of the cases cited by Extraction applies this "legal relationship" test. Mot. at 21-22 (collecting cases). Instead, each case considered the two elements—and only the two elements—required under Colorado law. *See Reishus*, 409 P.3d at 440 (covenant touched and concerned land where purpose was to have an agricultural property with quality hunting and included use restrictions); *Lookout Mtn.*, 867 P.2d at 75 (covenant touched and concerned land

because it was imposed for the benefit of the subdivision as a whole by protecting property values and ensuring a general plan of construction); *Cloud*, 857 P.2d at 440-41 (covenant for division of gross receipts from use of guest rooms touched and concerned the land because it benefitted owners); *Bigelow*, 833 P.2d at 767 (subordination rider did not touch and concern land where parties' entitlement to use of land was not increased and no improvements were made).

86. Even if the Court applied Bigelow's "legal relationship" test, the TSAs easily satisfy it. This test "turns on whether a covenant materially affects the promisor's legal relationship to the land itself, as measured by whether the covenant makes the estate more or less valuable." Bigelow, *supra*, at 652 (emphasis added). Additionally, the covenant must "operate primarily to benefit the covenantee … in the exercise of his privilege as owner of the soil." *Id.*

87. As discussed above, the TSAs significantly increase the value of Extraction's mineral estate, and benefit any subsequent producer in the Dedication Areas, not simply Extraction as the owner of chattel. *See supra* Sec. II, ¶¶ 72-73; *see also Alta Mesa*, 613 B.R. at 103-04.

88. Extraction's title to the crude oil is irrelevant. *Contra* Mot. at 4, 16, 20, 24. In *Southwest Pipe Line Co. v. Empire Natural Gas Co.*, the court rejected a similar argument under Oklahoma law, holding title was irrelevant, as the agreement created an easement for the buyer to build gathering pipelines on the leasehold, constituting an interest in the land. 33 F.2d 248, 249-50 (8th Cir. 1929). Colorado law is in accord. *See Universal Res. Corp. v. Ledford*, 961 P.2d 593, 595 (Colo. App. 1998) (free use clause created real covenant even though estate owner had no title to production). The TSAs benefit and burden Extraction's interests in the Dedication Areas, thus touch and concern the land. *See supra* sec II, ¶¶ 72-76; *see also Cloud*, 857 P.2d at 440.

C. Horizontal Privity Is Not Required to Create a Covenant in Colorado.

89. Extraction argues Colorado law requires privity of estate, or horizontal privity, between the parties to create a covenant running with the land. *See* Mot. at 13-20. This is incorrect.

90. Extraction primarily cites two Colorado Supreme Court cases decided in 1907 and 1954. Contrary to Extraction's argument, although both *Farmers' High Line Canal & Reservoir Co. v. New Hampshire Real Estate Co.*, 92 P. 290 (Colo. 1907), and *Taylor v. Melton*, 274 P.2d 977 (Colo. 1954), reference the concept of "privity of estate" both cases actually focused on vertical privity. For example, *Farmers'* concerned whether a written agreement by a canal owner to furnish water created a covenant that bound the current canal owner. *See* 92 P. at 293. Similarly, in *Taylor*, the issue was whether the defendant was bound by a restriction that was not in the defendant's deed, and was only in the deed of his predecessor in title. *See* 247 P.2d at 981-82. No Colorado court has referenced the concept of privity of estate or horizontal privity since 1954.

91. The year after *Taylor* was decided, the Colorado Supreme Court held a restrictive covenant ran with the land, even though it was never in the defendant's chain of title, and that it could be enforced even between parties that had no direct contractual relations. *See Pagel v. Gisi*, 286 P.2d 636, 638-39 (Colo. 1955). Privity was unnecessary to create the covenant. *See id.*

92. Every subsequent Colorado decision regarding covenants running with the land—including the cases cited by Extraction—has expressly stated the only requirements to create a real covenant are (1) the parties' intent, and (2) the covenant touches and concerns the land. *See*, *e.g.*, *Reishus*, 409 P.3d at 440 (containing no reference to horizontal privity requirement); *DeJean v. Grosz*, 412 P.3d 733, 739 (Colo. App. 2015) (same); *In re Banning Lewis Ranch Co.*, 532 B.R. 335, 345 n.11 (Bankr. D. Co. 2015) (same); *MidCities Metro. Dist. No. 1. v. U.S. Bank Nat'l Ass'n*, 2013 WL 3200088, at *3 (D. Colo. June 24, 2013) (same); *Lookout Mtn.*, 867 P.2d at 74 (same); *Cloud*, 857 P.2d at 440 (same); *Bigelow*, 833 P.2d at 767-68 (same).

93. The Fifth Circuit reached the same conclusion after conducting a "survey of Colorado case law." *TBI Expl.*, 2000 WL 960047, at *4 (only elements required under Colorado

law are "intent by the parties to the covenant that the covenant runs with the land" and "the covenant must 'touch and concern' the land.") (collecting cases). Modern Colorado courts do not recognize a privity requirement. *See, e.g.*, *Reishus*, 409 P.3d at 435-441 (finding amended ownership agreement created covenant running with the land even though there was no conveyance of any real property interest); *see also* Restatement (Third) Property § 2.4 (2000) (the horizontal privity requirement is no longer needed to ensure covenants will be recorded because "[i]n modern law, the Statute of Frauds and recording acts perform that function").

94. Extraction's reliance on C.R.S. § 38-30-121 also is misplaced. The statute simply provides that when a deed concerning real property is conveyed, the foregoing covenants run with the land. *See* C.R.S. § 38-30-121. It does not state that a conveyance of real property is necessary to create a covenant. Nothing in the statute disturbs Colorado's common law requirements on covenants running with the land, and no Colorado court has held otherwise.

95. Even if horizontal privity is required under Colorado law, and it is not, it has been satisfied. [redacted] This was a conveyance of real property to PRM. *See Badlands*, 608 B.R. at 874 (horizontal privity satisfied through simultaneous asset transfer).

96. Extraction argues even if a property right was granted to the Companies, it would not satisfy horizontal privity, because such property right would not flow from Extraction's mineral interests. *See* Mot. at 16 (citing *In re Sabine Oil & Gas Corp.*, 734 F. App'x 64, 67 (2d

Cir. 2018)). In *Badlands*, the court rejected a similar argument, explaining, "unlike in *Sabine*, the covenants burden Producers' real property interests (the Dedicated Reserves and the Producers' interests in the Leases) in the context of a simultaneous conveyance of real property interests (the Gas Gathering and Saltwater Disposal Systems) to [the midstream company], both of which are located in the same geographic area (the [Area of Mutual Interest])." 608 B.R. at 874.

97. [redacted]

98. [redacted] *See Booker v. Chreokee Water Dist.*, 651 P.2d 452, 453-54 (Colo. App. 1982) (a contractual license becomes a property right when coupled with an interest); *see also Private Right of Way*, BLACK'S LAW DICTIONARY (11th ed. 2019) (defining "private right of way" as an easement); Jon W. Bruce & James W. Ely, Jr., *The Law of Easements & Licenses in Land* § 11:8 (June 2020) ("A license may be coupled with an interest when the licensee owns personal property on the servient land related to the purpose of the license.") (collecting cases).

99. While horizontal privity is not required under Colorado law, the facts demonstrate that horizontal privity exists between the Companies and Extraction in connection with the TSAs.

100. The Companies reserve their rights in all respects to supplement this Response at or prior to the hearing on the Motion.

CONCLUSION

For the reasons set forth above, Extraction's Motion should be denied.

Dated: September 18, 2020
Wilmington, Delaware

/s/ Curtis S. Milller

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EXHIBIT A

IN THE UNITED STATES BANKRUPTCY COURT
FOR THE DISTRICT OF DELAWARE

In re: EXTRACTION OIL & GAS, INC., *et al.*,[1] Debtors.	Chapter 11 Case No. 20-11548 (CSS) (Jointly Administered)
EXTRACTION OIL & GAS, INC., Plaintiff, v. PLATTE RIVER MIDSTREAM, LLC AND DJ SOUTH GATHERING, LLC Defendants.	Adv. Proc. No. 20-5-833 (CSS)

DECLARATION OF ROGAN MCGILLIS

I, Rogan McGillis, declare under penalty of perjury as follows:

1. Since 2014, I have served as the Chief Financial Officer of ARB Midstream, LLC ("ARB"). ARB is a private oil and gas liquids midstream and marketing / logistics solutions company. I am a co-founder of ARB and member of the ARB's Board of Directors. Given my roles at ARB, I have supervisory responsibility over all financial aspects of ARB and its assets.

[1] The Debtors in the Chapter 11 Cases, along with the last four digits of each Debtor's federal tax identification number, are: Extraction Oil & Gas, Inc. (3923); 7N, LLC (4912); 8 North, LLC (0904); Axis Exploration, LLC (8170); Extraction Finance Corp. (7117); Mountaintop Minerals, LLC (7256); Northwest Corridor Holdings, LLC (9353); Table Mountain Resources, LLC (5070); XOG Services, LLC (6915); and XTR Midstream, LLC (5624). The location of the Debtors' principal place of business is 370 17th Street, Suite 5300, Denver, Colorado 80202.

2. For the past 10 years, I have been involved in negotiating and developing crude oil or other liquid hydrocarbon pipeline transportation projects. I am familiar with the financial and operational terms contained in these contracts, as well as the financial structures of transportation companies like ARB. In particular, I am familiar with the requirements needed to obtain equity and debt financing for transportation systems, and the general expectations of transportation companies on recovering capital investments and a return on those investments.

3. Based on my expertise and responsibilities at ARB, I have personal knowledge of the contract negotiations, pipeline construction activities, and operations described below.

ARB Midstream

4. ARB builds and operates pipeline systems to transport crude oil and other liquid hydrocarbons produced from wells throughout North America. The pipeline systems owned and operated by ARB are known as "in-field transportation systems" because they transport oil within a specific production area. In-field systems are different from large pipelines that transport production over long distances, often across interstate lines.

5. An in-field system typically is connected to a producer's well or well pad, and the physical location of the leasehold. In some instances, producers will build, or contract with a third party to build, a central gathering facility that is connected to multiple wells. Production from the wells flows from the well pad to the central gathering facility, where it is connected to a "trunkline," or intermediate-haul pipeline, operated by ARB. Whether connected directly to a well or to a central gathering facility, ARB's system will deliver the production through its pipeline to a designated downstream location. At these downstream delivery points, the production is either sold or delivered into another transportation pipeline, as directed by the producer.

6. In-field gathering systems can require dozens, even hundreds, of miles of pipelines. ARB does not purchase the property necessary to install the pipeline. Instead, like most midstream transportation companies, ARB negotiates and purchases rights of ways or easements from property owners (including both producers and individual landowners) in order to install its underground pipelines. ARB also is required to obtain permits from local and state governments to build pipelines under each road, river, and ditch crossing, as well as additional permits for the construction of the pipeline and facilities themselves. Based on my experience in the industry, and my knowledge over the course of 10 years developing pipeline transportation projects, I am generally familiar with the processes and requirements necessary to obtain use permits. The permitting process is especially laborious and complicated when constructing pipelines in populated areas, like the Denver-Julesburg Basin (the "DJ Basin"), located north of Denver, Colorado. This is because the pipelines are built under the properties of hundreds of different property owners and often cross large highways or other populated crossings.

7. The process of acquiring rights of ways, easements, permits, installing the pipelines and related facilities, and operating an in-field transportation system costs millions, potentially hundreds of millions, of dollars. Building an in-field transportation system therefore requires a similar multi-million-dollar commitment. The capital investment, and any return on that investment, are not recovered until many years later. This has been my experience with every transportation system that ARB has operated, and is no different than any transportation system in the industry.

8. To secure its investment in a transportation system, ARB seeks to obtain both dedications from at least one shipper, as well as additional minimum financial commitments, if

possible, from shippers. A dedication means that the shipper has dedicated all of its interests in current and future oil production to be transported on the company's pipeline system for a contractually defined term, or even the life of the underlying oil and gas leases. As a dedication does not carry any financial commitment until crude oil is actually delivered into the pipeline system, midstream transportation companies often seek to obtain a minimum financial commitment in addition to the dedication. A minimum financial commitment means that the shipper has committed a minimum monthly, or annual, amount of revenue to ARB regardless of whether the shipper actually ships any oil in that corresponding period. A minimum financial commitment allows ARB to obtain the type of financing that requires the certainty of cash flow that only a minimum financial commitment can provide. Minimum financial commitments, however, have become quite rare in the midstream industry as they create financial risk for producers. As discussed below, ARB was able to obtain a minimum financial commitment from Extraction, in addition to a dedication of Extraction's oil reserves, because the parties decided to enter into a joint venture.

9. In most cases, a minimum financial commitment is significantly lower than the estimated production that ARB expects or is needed to recover its investment; it is simply an additional assurance that ARB will have, at least a portion, of the cash flow necessary to cover operating costs or interest expenses. A dedication also allows ARB to obtain the financing it needs to construct and operate a pipeline system. In this case however, the total amount of oil in the ground, *i.e.*, the dedicated interest, is used to determine how much upfront capital can be spent and what rate is needed to recover our investment over the life of the contract or project.

10. The dedication of the oil is the most valuable long-term component of an in-field gathering contract. This is because, in the oil and gas industry, I understand, and ARB understands, that a dedication is a binding commitment that applies to a shipper's successors, and cannot be terminated except as permitted by the parties' agreement. Otherwise, ARB and any midstream company would be unable to obtain the investment capital needed to install a crude oil transportation pipeline and a producer would, therefore, not be able to produce oil from its mineral interests if it had no means of safely and economically transporting the oil over the long distances that our pipelines facilitate. This is based on my experience in the industry, and my knowledge of the risks evaluated by investors over the course of my 10 years of negotiating and evaluating pipeline transportation projects.

11. ARB has contracts that do not contain minimum financial commitments, and that do not obligate a shipper to transport any volumes on the pipeline system. It is my preference, however, to enter into these contracts only after contracting with a dedicated shipper whose contract and financial commitment justifies, at least part of, the construction of the pipeline, and where the pipeline has excess capacity to accommodate the additional production.

12. In my experience, and based on my knowledge of ARB's contracts and the contracts of other midstream providers, dedications are common in the in-field gathering industry. I have seen dedications worded in different ways depending on the contract, but the purpose is to ensure the producer is obligated to deliver its current and future production into the pipeline so the transportation company can recover the cost of installing the pipeline system. Absent a commitment of both current and future production, transportation systems simply would not be able to obtain financing and would not be built. I have reviewed some of the documents produced

by Extraction in this proceeding [redacted]

13. The installation of a pipeline system has an immediate benefit to a producer. Once a well site is connected to an in-field transportation system, the value of the mineral estate is increased. Based on my experience in the oil and gas industry, I know that when a producer conducts a valuation of its acreage, a critical component of that valuation is the cost to get its production to market. The installation of a dedicated pipeline system increases the value of the mineral estate by lowering the cost of getting the production to market and saves that cost for any and all subsequent producers. I have seen this benefit on the reserve reports of multiple producers. The property's value is enhanced because the pipeline system ensures that production will be transported downstream for sale at costs less than alternative means of transportation. This is especially true where a producer has no alternative means of transporting its production, either because of a lack of infrastructure to transport the production by other means, or state or local restrictions on the use of tanker trucks. In those situations, a dedicated pipeline system greatly enhances the value of the mineral estate because absent ability to get the production to market, the minerals are worthless.

14. I know from my professional experience in Colorado that pipelines are particularly important in populated areas. Without a pipeline connection, a producer's alternative is to use tanker trucks to transport its crude oil. This is not a popular method of transportation in the communities of DJ Basin. Tanker trucks transport crude oil, a highly combustible and flammable product, on roadways. Tanker trucks are more disruptive to populated communities, because they are noisy, create dust and road wear that must be repaired, and increase traffic on local streets and

highways and are also susceptible to traffic accidents. Needless to say, the more wells operated by a producer, the more trucks are needed to transport oil without a pipeline in place. In some instances, a producer will simply not be able to secure a permit to drill a well without a pipeline gathering solution as the alternative transportation method is too great of a public concern to allow the development of the minerals, rendering the mineral interest worthless. As stated above, a pipeline significantly enhances the value of the mineral interest in this situation.

15. Residents of Colorado towns such as Greeley, Broomfield, and Aurora frequently have opposed oil and gas production unless the producer agrees to use pipelines instead of tanker trucks. Greeley residents have been hostile to the use of tanker trucks, and this was a topic of discussion in the negotiations with Extraction discussed below. In recent years, the city governments of Broomfield and Aurora have adopted restrictions on producers' use of trucks to transport oil production, which again, without a pipeline transportation solution significantly impairs the value of the interests.

Platte River Midstream

16. In September 2016, ARB acquired the predecessor entity to Platte River Midstream, LLC ("PRM") to build and operate a crude oil transportation system in Larimer and Weld Counties, Colorado. PRM acquired approximately 10 miles of a crude oil transportation system in Weld County from Rimrock Gathering, LLC ("Rimrock"). When PRM acquired the system, Rimrock had a transportation contract in place with Bayswater Exploration & Production, LLC ("Bayswater"), a producer in the DJ Basin.

17. The following year, Extraction Oil & Gas, Inc. ("Extraction") acquired Bayswater's wells, and thus was the successor to Bayswater's transportation contract with PRM.

18. In late 2016, Extraction began negotiating with ARB to expand PRM's transportation system, so that it would connect to other wells Extraction operated, and intended to drill and operate, in Larimer and Weld Counties, Colorado. I was personally involved in these negotiations, as was ARB's Chief Executive Officer at the time, Adam Bedard. Extraction was represented by Kevin Williams and Travis Winger in the negotiations. Neither Matt Owens nor Mark Erickson had discussions with ARB's representatives regarding the negotiations.

19. In the course of the negotiations, Mr. Williams explained that Extraction wanted to undertake an aggressive drilling program in Larimer and Weld Counties, Colorado. He made clear that it was important for Extraction to secure pipeline transportation before undertaking its drilling program, and raised the concern over Extraction's use of tanker trucks as its current mode of transporting its oil. In particular, he noted that communities in the Greeley area were strongly opposed to Extraction's use of tanker trucks, and expressed that a pipeline solution was necessary in order to avoid issues with obtaining drilling permits.

20. Mr. Williams made me aware that Extraction received particular resistance to its drilling proposals from the residents of Triple Creek, outside of Greeley. Extraction planned to drill 22 horizontal wells from its Triple Creek pad, and had no pipeline connection at the time. Mr. Williams stated that the community was vocal in its opposition to Extraction's drilling plan, as well as its lack of a pipeline to transport production. Per Extraction's public filings and statements at the time, it was well understood that the Triple Creek wells were critically important to the business plan and success of Extraction. Mr. Williams made plain that the ability to quickly connect a pipeline to Extraction's planned Triple Creek wells was a priority as Extraction needed the Triple Creek pad online to hit its quarterly requirements.

21. I was aware during the negotiations that Extraction operated its own small midstream company in the vicinity, a wholly owned subsidiary called XTR Midstream LLC ("XTRM"). [redacted] XTRM had run into difficulties, however, in securing rights of way near Great Western Industrial Park that were needed to continue the pipeline development to its intended delivery location in Lucerne, Colorado. Extraction did not plan to build trucking infrastructure.

22. During the negotiations, Mr. Williams told me that, if Extraction was able to reach an agreement with PRM, then Extraction would no longer need to operate XTRM on Extraction's acreage that would be served by PRM's pipeline. Mr. Williams also explained that Extraction had concerns about not knowing ARB or PRM's operations team, and therefore requested to form a joint venture with ARB to jointly own PRM. This would provide Extraction with an equity interest in the transportation system, as well as a voice in PRM's management. Extraction also proposed that PRM agree to a secondment agreement, whereby two XTRM employees would work with PRM on operations. Extraction indicated that although ARB would acquire the current assets of XTRM, they had future plans to potentially grow their XTRM business in other areas and requested Options to increase its ownership, and potentially acquire all remaining ownership of PRM. These Options were also put in place because Extraction indicated that the gathering system was viewed as an extension of their production facilities, and critical to the operations of Extraction and needed to have the ability to gain control of the business should ARB fail in its obligations under the contract.

23. During the negotiations, it was ARB and PRM's intent that Extraction dedicate all of its current and future production from the agreed-upon dedication area to PRM's transportation system. Given the deal terms, neither ARB nor PRM could justify undertaking the financial investment of expanding the pipeline system unless Extraction was willing to dedicate and commit all of its interest in production in, under, and attributable to the dedication area, whether current or in the future for, at minimum, the term of the agreement. Extraction's representatives never expressed a contrary intention to me or Mr. Bedard. Based on Extraction's press release heralding its pipeline agreement, as well as the fact that it was a joint venturer in the pipeline system, and that [redacted] I believe Extraction shared ARB and PRM's intent.

24. To accommodate Extraction's goals and desires, ARB agreed to form a joint venture with Extraction, through XTRM. Accordingly, on April 14, 2017, the parties entered into four contemporaneous and integrated agreements to achieve Extraction's goals:

a. ARB and XTRM entered into a First Amended and Restated Limited Liability Company Agreement (the "LLC Agreement"), pursuant to which the parties formed a new entity, Platte River Holdings, LLC ("PRH"). PRM became a wholly owned subsidiary of PRH. ARB owned a majority membership interest in PRH, and XTRM owned a minority interest in PRH. ARB also was designated as PRM's manager.

b. PRM and Extraction entered into a First Amended and Restated Transportation Agreement (the "PRM TSA"). Pursuant to the PRM TSA, PRM agreed to undertake the expense and effort of constructing, installing, and operating an extensive network of pipelines and related facilities (the "PRM Transportation System"). Extraction, in turn, agreed to

dedicate and commit all of its interests in crude oil in, under, and attributable to certain locations in Larimer and Weld Counties to the PRM Transportation System (the "PRM Dedication Area").

[redacted] I specifically recall communications from Mr. Williams that Extraction wanted the "value of its reserves acknowledged" through an additional equity grant. ARB agreed as obtaining a dedication of all of Extraction's interests within the PRM Dedication Area was necessary before undertaking the financial investment of expanding the pipeline system. As I described above, the PRM TSA was negotiated and drafted with the common understanding and intent to cover both current and future production for the entire term of the agreement. This was discussed between the ARB and Extraction representatives.

c. [redacted]

d. PRM and XTRM entered into an Assignment of Easements pursuant to which XTRM assigned and conveyed to PRM its right, title, and interest in the easements and rights-of-ways XTRM had previously obtained related to Extraction's wells within the PRM Dedication Area. It was generally agreed that it would be PRM's responsibility to obtain additional rights-of-ways in connection with any subsequently drilled wellsite within the PRM Dedication Area, however, there were critical wellsites that XTRM had already undertaken acquiring rights-of-way, *i.e.*, Triple Creek, and it was agreed that XTRM would finalize those agreements and immediately transfer the rights-of-way to PRM once complete.

25. I have reviewed PRM's financial statements to determine the amount of capital PRM has spent to build and operate the PRM Transportation System pursuant to the PRM TSA.

[redacted]

26. The PRM Transportation System is custom built to connect directly to Extraction's well pads. This requires Extraction to prepare each well pad for connection to the pipeline and for PRM to install well-specific custom connection to each well pad. Because of the need to connect directly to each well pad, it is necessary for PRM to obtain easements or rights-of-ways to access the surface of Extraction's leaseholds to install the necessary infrastructure for the pipeline. This is why the Assignment of Easements from XTRM was necessary and why Extraction was required to grant additional easements to PRM for each additional well pad.

27. Before expanding the transportation system, PRM also had to obtain use permits from each local city or county. As described above, the process for permitting a new pipeline is a time-consuming process as the local cities and counties require a detailed application package including proposed routes, right-of-way and easement information, environmental and public impacts, and other project-specific details. As explained above, permits are required for each road, river, and ditch crossing that the pipeline crosses. Additionally, certain counties have additional permitting requirements. For example, to operate in Weld County, PRM was required to obtain a land use permit to operate in residential communities, such as Greeley, Colorado, where Extraction wanted to drill a significant number of new wells. PRM also had to obtain a Location Assessment

for Pipelines ("LAP"), which took several months to complete. In some cases, it took over 12 months to obtain the permits necessary to expand the PRM Transportation System.

28. During negotiations, Mr. Williams expressed that Extraction felt it had been "taken advantage of" by a company it had contracted with for long-haul transportation who had sold its long-haul transportation system shortly after contracting with Extraction. Given Extraction's stated concern over being "taken advantage of," Extraction communicated its desire to have express contractual assurance that it could control the identity of the party installing and operating the transportation system. Accordingly, Mr. Williams wanted restrictions on the parties' ability to transfer or assign their interests in PRH as well as their interests in the PRM TSA. These provisions were also important to ARB, as well, because it benefitted ARB to partner with an oil and gas producer who would continue to dedicate, and deliver crude oil to the PRH partnership.

DJ South Gathering

29. In October 2017, Extraction began negotiating with ARB to build a new in-field gathering system that would transport Extraction's crude oil production from wells located in the City and County of Broomfield, Colorado, and Adams, Arapahoe, Boulder, and Weld Counties, Colorado. I was personally involved in these negotiations, as was ARB's Chief Executive Officer at the time, Adam Bedard. Similar to the PRM transaction, Extraction was again represented by Kevin Williams and Travis Winger in the negotiations. Matt Owens and Mark Erikson were involved in high-level strategic discussions with ARB regarding the joint venture, but neither were directly involved in the negotiations.

30. During negotiations, Mr. Williams expressed to me that as ARB and Extraction were already partners in a joint venture, it made sense for ARB to install, construct, and operate

the new transportation system. Mr. Williams, however, expressed that Extraction still wanted consideration for the dedication of reserves in the form of additional equity interest in the PRH, as it had received with the PRM dedication.

31. Accordingly, on January 17, 2018, ARB formed a limited liability company, DJ South Gathering, LLC ("DJ South") as a wholly owned subsidiary of PRH to build and operate the new transportation system (the "DJ South Transportation System"). ARB is the manager of DJ South. PRM and DJ South are referred to together as the "Companies."

32. During the negotiations, it was ARB and DJ South's intent that Extraction dedicate all of its current and future production from the agreed-upon dedication area to DJ South's transportation system. Given the deal terms, neither ARB nor DJ South could justify undertaking the financial investment of constructing a new pipeline system unless Extraction was willing to dedicate and commit all of its interest in production in, under, and attributable to the dedication area, whether current or in the future, as well as make a financial commitment to provide cash flow assurance. Extraction's representatives never expressed a contrary intention to me or Mr. Bedard. Based on fact that Extraction was an owner of the pipeline system through its ownership interest in PRH, I believe Extraction shared ARB and DJ South's intent.

33. To accommodate Extraction's goals and desires, on May 16, 2018, the parties entered into two simultaneous and integrated agreements:

a. XTRM assigned all of its rights and interests under the LLC Agreement to Elevation Midstream, LLC ("Elevation") pursuant to a Joinder and First Amendment to the LLC Agreement (the "LLC Amendment") between XTRM, Elevation, and ARB. I was aware during the negotiations that at the time, Elevation was a wholly owned subsidiary of Extraction. [redacted]

[redacted]

b. DJ South and Extraction entered into a Transportation Services Agreement (the "DJ South TSA"). The PRM TSA and the DJ South TSA are referred to together as the "TSAs." Pursuant to the DJ South TSA, DJ South agreed to undertake the expense and effort of constructing, installing, and operating the DJ South Transportation System. Extraction, in turn, agreed to dedicate and commit all of its interests in crude oil in, under, and attributable to certain locations in the City and County of Broomfield, Colorado, and Adams, Arapahoe, Boulder, and Weld Counties, Colorado to the DJ South Transportation System (the "DJ South Dedication Area"). [redacted] As I described above, the DJ South TSA was negotiated and drafted with the common understanding and intent to cover both current and future production from the entire term of the agreement. This was discussed between the ARB and Extraction representatives.

34. I have reviewed DJ South's financial statements to determine the amount of capital DJ South has spent to build and operate the DJ South Transportation System pursuant to the DJ South TSA. [redacted]

35. Unlike the PRM Transportation System, which is directly connected to Extraction's well pads, the DJ South Transportation System connects to two downstream central gathering

facilities ("CGFs") that collect production from multiple wells. The CGFs are owned and operated by Elevation.

36. Because the new system would not directly connect to Extraction's well sites, it was important to ARB that the new contract provide additional protection to ARB to ensure that the DJ South Transportation System would not be displaced if Extraction assigned or sold acreage within the DJ South Dedication Area or the central gathering facilities. Mr. Bedard communicated this to Mr. Williams during negotiations and it is my understanding that it is for this reason that the DJ South TSA includes express language that the dedication runs with the land.

37. To date, Extraction has only drilled wells connecting to one of the CGFs, known as the "Badger CGF." Extraction, through Elevation, granted DJ South a right-of-way to access the Badger CGF and build and install the necessary infrastructure to connect the Badger CGF to the DJ South Transportation System. The DJ South Transportation System is ready to transport production from the second CGF if and when Extraction drills wells in those areas.

38. Similar to the PRM Transportation System, before constructing the DJ South Transportation System, DJ South also had to obtain use permits from each local city or county. As explained above, I am generally familiar with the processes and requirements necessary to obtain use permits, which is generally a time-consuming process. For example, in addition to obtaining the permits and assessments required by Weld County described above, DJ South also had to obtain a Conditional Use Permit ("CUP") to lay pipe in Adams County. A CUP application is generally hundreds of pages long and can take several months to obtain. It took DJ South over 24 months to obtain all permits necessary to construct the DJ South Transportation System and additional permitting is ongoing.

Compensation under PRM and DJ South TSAs

39. Under the TSAs, Extraction is required to pay PRM and DJ South a monthly tariff approved by the Federal Energy Regulatory Commission ("FERC") for the volumes it delivers into the Platte River Transportation System. I have reviewed monthly invoices for both PRM and DJ South to determine the average amount of monthly tariff paid by Extraction to PRM and DJ South. [redacted]

40. Extraction is also required to pay a fixed monthly payment to the Companies, regardless of the volumes it actually delivers into the Transportation Systems. The fixed monthly payment is offset by the monthly tariff. The fixed monthly payment represents the monthly amount of the contractually-defined "total financial commitment" that Extraction agreed to pay the Companies under the TSAs. As explained above, the purpose of a fixed monthly payment is to ensure that the transportation company receives some return on its investment even if the producer's wells are uneconomical in any given month. In my experience, however, the amount of the monthly tariff is designed to exceed the fixed monthly payment as the fixed monthly payment is based on 40 percent of expected production.

41. I have reviewed the TSAs to determine the amount of the "total financial commitments." [redacted]

[redacted]

42. In my role as Chief Financial Officer, I am familiar with how the total financial commitments are determined and their purpose. As explained above, the purpose of the total financial commitments is to service the debt of ARB's upfront financial commitment necessary to build the transportation system. [redacted]

43. As discussed above, it was understood between ARB and Extraction and that the Companies could not justify undertaking the financial investment of constructing the Transportation Systems unless Extraction was willing to dedicate and commit all of its interest in production in, under, and attributable to the dedication area, whether current or in the future. It is my understanding that the dedications under the TSAs are significantly more valuable than the total financial commitments, because they are based on the total amount of current and future production from the Dedication Areas, and based on the value of the crude oil production in the ground. This is based on discussions with our lender, my experience in the industry, and my knowledge of the risks evaluated by investors over the course of 10 years negotiating and developing pipeline transportation projects.

I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct.

Executed on September 17, 2020



Rogan McGilllis
Chief Financial Officer
ARB Midstream, LLC

EXHIBIT B

District Court, City and County of Denver, Colorado 1437 Bannock Street Denver, CO 80202	DATE FILED: August 23, 2017 9:04 AM CASE NUMBER: 2016CV34274
Plaintiffs: NEIGHBORS AFFECTED BY TRIPLE CREEK v. **Defendants:** COLORADO OIL AND GAS CONSERVATION COMMISSION; **Defendant-Intervenors:** COLORADO OIL AND GAS ASSOCIATION; EXTRACTION OIL & GAS, INC.	**▲ COURT USE ONLY ▲** Case Number: 16CV34274 Courtroom: 209
ORDER	

This Matter comes before the Court pursuant the Plaintiff's ("Neighbors") Opening Brief filed on March 8, 2017; Defendant Extraction Oil & Gas, Inc.'s ("Extraction") Answer Brief filed on April 12, 2017; Defendant Colorado Oil and Gas Association's ("COGA")[1] Answer Brief filed on April 12, 2017; and Plaintiff's Reply Brief filed on May 3, 2017. The Court held a hearing on Plaintiff's Motion to Strike and the Court granted this Motion as to documents 5, 7, 8, and 9 of the joint appendix. As such, these exhibits were not considered in this ruling. After considering the pleadings of the parties and the relevant record the Court enters the following findings and Order:

I. Relevant Background

On December 23, 2013, Mineral Resources applied to the Colorado Oil and Gas Conservation Commission ("Commission") to approve an industrial-scale oil and gas development ("Triple Creek") amid residential subdivisions in Greeley (via Form 2A). Initially, Mineral Resources intended to install the wells in the operation 1,000 feet from any homes. The Commission approved the Form on April 18, 2014. A year later, in September of 2015, Mineral Resources transferred their interest in the site to Extraction.

[1] For ease of readability, throughout this Order I collectively refer to Extraction and the Commission as "the Industry" in areas where the distinction is immaterial as the arguments of both are materially the same.

Moving forward with the belief that the Commission had already approved the development of the site, Extraction applied to the City of Greeley for a Use by Special Review ("USR") permit on May 21, 2014. As part of the USR review process, Extraction held a neighborhood meeting on September 25, 2014. Neighbors assert that at this meeting Extraction stated that the proposed operation would be "tankless;" that the produced product would be transported via pipeline to an alternative location. Extraction held a second neighborhood meeting on November 18, 2015, and stated they would not be going tankless, but rather would be installing 24 tanks using trucks to transport the product.

The City of Greeley Planning Commission denied the USR request on January 5, 2016. This was appealed by Extraction to the Greeley City Council who overturned the decision of the Planning Commission. Extraction then notified the Commission of plans to install additional production facilities and relocating the access road for the site. Neighbors filed numerous complaints and asked Extraction to file an amended Form 2A that was in compliance with the Commissions regulations. Extraction filed the amended form on June 30, 2016, which the Commission approved. Neighbors are now contesting this approval. Specifically, Neighbors alleges that the Form did not contain an evaluation of alternative locations for the project and did not leave sufficient time for public comment of the denial. Neighbors also requested a hearing before the Commission. The Commission denied the request.

In November of 2016, Extraction broke ground on the project and began drilling operations in January of 2017.

II. Standard of Review

Pursuant to the Colorado Administrative Procedure Act, the Commission's approval of the Form 2A permits constitutes final agency action for purposes of review. C.R.S. §24-4-106(7) states a reviewing court shall hold unlawful and set aside agency action only if it finds the agency action is:

> [A]rbitrary or capricious, a denial of statutory right, contrary to a constitutional right, power, privilege, or immunity, in excess of statutory jurisdiction, authority purposes, or limitations, not in accord with the procedures or procedural limitations of this article or as otherwise required by law, an abuse or clearly unwarranted exercise of discretion, based upon findings of fact that are clearly erroneous on the whole record, unsupported by substantial evidence when the record is considered as a whole, or otherwise contrary to law.

"[A]dministrative proceedings are accorded a presumption of validity and all reasonable doubts as to the correctness of administrative rulings must be resolved in favor of the agency." *Von Sickle v. Boynes*, 79 P.2d 1267, 1272 (Colo. 1990). Factual findings, including assessing the credibility of witnesses, lies within the discretion of the agency, and the reviewing court cannot make an independent evaluation of the evidence and substitute its judgment for that of the agency. *Bodaghi v. Dep't of Natural Res.*, 995 P.2d 288, 303 (Colo. 2000). However, the

reviewing court interprets the law, and is not bound by an agency interpretation which misconstrues the law. *Echostar Satellite, LLC v. Arapahoe Cnty. Bd. Of Equalization*, 171 P.3d 633, 636 (Colo. App. 2007).

III. Analysis

The Colorado Oil and Gas Conservation Act regulates the oil and gas industry in Colorado. The Commission has adopted regulations under this act including the Large Urban Mitigation Area Rules ("UMA"). Under the UMA Commission Rule 604.c.(2)E.i., production facilities are required to be located as far as possible from building units. To accomplish this alternative locations must be evaluated in the site approval process, and economic and technical data supporting the site decision must be submitted.

a. Standing

First, I will discuss the issue of whether Neighbors have standing to bring this lawsuit. The State Administrative Procedure Act provides that any person adversely affected by final agency action is entitled to judicial review. *See* C.R.S. 24-4-106, 34-60-111. Clearly, there was a final agency action in this case through the grant of the permit to Extraction. Neighbors is a community association formed in November of 2015. Neighbors argue they have standing through organizational or associational standing, which requires three elements: (1) the members of the association would have standing to sue in their own right; (2) the interests the association seeks to protect are germane to the organization's purpose; and (3) neither the claims asserted nor the relief requested would require participation of the individual members of the lawsuit. As standing is a mirrored principle of federal as well as state law, I find several federal cases illustrative to determine whether the Plaintiffs have standing.

The Industry argues that the Standing Declarations submitted by Neighbors should be stricken from the record. I am not convinced, as standing can be established through the complaint, "along with any other evidence submitted on the issue of standing." *Bd. of Cty. Comm'rs, La Plata Cty. v. Bowen/Edwards Assocs., Inc.*, 830 P.2d 1045, 1053 (Colo. 1992). I agree with Plaintiffs and the relevant case law that standing in Colorado has traditionally been a fairly easy hurdle to overcome. *Ainscough v. Owens*, 90 P.3d 851, 856 (Colo. 2004). Plaintiffs allege real injuries in the form of noise pollution, aesthetic interests and threat of exposure to potentially hazardous materials. *See Nat'l Wildlife Fed'n v. Cotter Corp.*, 665 P.2d 598, 603 (Colo. 1983) (holding "business, economic, aesthetic, governmental, recreational, or conservational interests" to be among some of the interests that can form the basis for an injury in fact to confer standing). Based on the information in the record, and the standing declarations, I find that Neighbors satisfy the injury in fact requirement for standing and the members would have standing to sue in their own right. I further find that the interests the association is seeking to protect are germane to its purpose. Clearly, a neighborhood association has an interest in keeping the neighborhood free from pollution and furthering the aesthetic interests of the neighborhood and increasing property value. Finally, I find nothing in the record to indicate that

the participation of an individual Plaintiff is required for this lawsuit to continue. Therefore, I find that Plaintiffs have standing to bring this lawsuit.

b. Location of production facilities & alternative site analysis

Turning to the merits of the appeal, I will first address Neighbor's contention that the approval of Extraction's Form 2A permit was arbitrary and capricious based on the alternative site analysis conducted. Specifically, Neighbors contend that the alternative site analysis submitted by Extraction was arbitrary and capricious because it did not sufficiently explain the reasoning behind their decision not to choose the alternative sites proposed. *See* AR 260-262. Further, Neighbors contend that there was error because the operator failed in their duty to identify alternative site analyses as the alternatives proposed were proposed by Plaintiffs former counsel and not the operator.

It is undisputed that the Triple Creek site meets the definition of a Large Facility in an Urban Mitigation Area (LUMA), and it governed by the Large Area Mitigation Area (UMA) Rules adopted in 2016. Under the Rules, LUMA's must comply with Commission Rule 604. C.(2)E.i. which requires multi-well production facilities to be located as far as possible from building units. The Rule clearly requires that the production facilities be situated "as far as possible" from building units, but gives little guidance as to how to determine whether a production facility is indeed located as far as possible.

Neighbors argue that Rule 604 requires an alternative site analysis as contemplated by rule 305A.b.(2). The industry counters that they are not governed by the requirements of Rule 305 because they meet one of the noted exceptions. Specifically, Rule 305A.a. requires an operator of a proposed facility to submit a written notice of intent ninety (90) days before initializing the Form 2A process unless one of the exceptions is met. If one or more of the listed exemptions applies then the proposed LUMA is "not required to provide a Notice of Intent to Construct a Large UMA Facility or to engage in the consultation processes described in Rule 305A.a-d." (specifically included in the consultation process described in Rule 305 is the requirement of alternative site analyses).

It is not disputed that the Industry meets several of the exemptions under Rule 305. Neighbors, however, argues that an alternative site analysis is required to meet the requirement of Rule 604 that the production facility be as far as possible from building units. I do not agree with this analysis. The requirements of Rule 305 specifically relate to the location of the entire site, whereas Rule 604 relates to the siting of the production facilities once the site has already been chosen. This is supported by the language of Form 2A and the language of the Rules. Specifically, Rule 305 A.e.1.b. provides an exemption for "an existing agreement regarding siting of oil and gas locations. " As there was already an existing agreement in place between the Operator and the local government concerning the location of the site, there was no need for an alternative site analysis to be conducted. *See* AR 278.

Therefore, I do not find it necessary to analyze the adequacy of the site analyses performed by Extraction or utilized by the Commission as they were not required in this instance.

c. Best Management Practices

Under Rule 604.c., the Commission is required to consider site-specific mitigation measures and best management practices for the site. Neighbors argue the best management practices considered by the Commission were inadequate. Specifically, Neighbors argue the best management practices raised during public comment were either not considered by the Commission or were not considered adequately. Pursuant to the Commission's Rules and Regulations, the Commission is required to consider mitigation measures that are site-specific of any oil and gas locations prior to approval. However, the Director is also required to give substantial deference to any mitigation measures suggested by the local government with land use authority. See 2 Colo. Code Regs. §404-1:604.c.(4)D.

First, Neighbors argue that the Commission failed to consider high vapor pressure (HVP) oil gathering technology. HVP oil gathering technology measures the quantity of oil and gas at each well head before oil is transported into pipelines, which reduces onsite oil tank and truck storage. Neighbors argue this is the best available technology and was raised several times during public comments. Specifically, Neighbors state that the Commission was required to articulate on the record why this technology was not utilized at the Triple Creek Site. Second, Neighbors argue that the Commission failed to adequately explain why pipelines were not required at the Triple Creek site. This was an issue that was contested by the public and addressed in several public comments. Third, Neighbors argue that the Commission failed to consider the noise mitigation measures brought up during public comment.

The Industry counters that numerous BMPs were considered by the Commission, and that substantial deference was given to those mitigation measures suggested by the local government with land use authority. Further, the Industry argues that the BMPs suggested by Neighbors were not cost-effective or reasonable. Specifically, the Industry argues that the HVP technology and the use of a pipeline were not available due to a lack of infrastructure.

I agree that the Commission has broad discretion in deciding which BMPs to implement in the permitting process. However, this does not mean that that Commission can simply disregard public comments and provide no explanation as to why certain BMPs were rejected, especially in such a hotly contested permitting issue. Colorado Statute does not require an agency to address all public comments on the record. However, the Commission *is* required to "consider all submissions." C.R.S. §24-4-103(4)(A). Although the Industry argues that the record is replete with examples of the Commission considering the feasibility of an HVP or pipeline network, I do not agree that a public comment stating that pipelines are not economic and an

answer from Extraction stating that "Extraction remains committed to using the best technology available on all locations and is still exploring opportunities to use oil pipeline takeaway, but at this time are unable to commit to definitive timelines" shows that the Commission considered feasibility of an HVP or pipeline network. The Commission simply indicated that "no liquids gathering pipeline infrastructure is present and available in the vicinity of this oil and gas location," without any explanation. AR 272.

The record indicates that several community members and council members recount that Extraction initially stated that the operation would utilize pipelines instead of trucks and would be a "tankless" facility. AR 204-16. It was arbitrary and capricious for the Commission to make a blanket statement that Extraction had not initially committed to a tankless facility when there is ample evidence to support this in the record. Even though Extraction did not commit to a tankless facility on paper, their representation to the community that the facility would be tankless warrants the Commission looking into why the feasibility of this procedure changed. At a minimum, the Commission should have adequately explained why the location lacked the appropriate infrastructure, making tankless operation not feasible. *See Johnston v. City Council of Greenwood Vill.*, 177 Colo. 223, 226 (1972) ("capricious or arbitrary exercise of discretion can arise where a board neglects to use reasonable care in procuring such evidence as it is authorized by law to consider"). The Commission should have considered the public comments evidencing Extraction's initial intent and should have considered in further detail the infeasibility of a tankless facility at this site. "It is an elementary principle of administrative law that an administrative agency must provide reasons for its decisions." *Fisher v. C.I.R.*, 45 F.3d 396 (10th Cir. 1995).

I am also unconvinced that the Commission did not act arbitrarily and capriciously in their analysis of the noise mitigation measures. The Commission failed to address noise mitigation BMPs raised by the Colorado Department of Public Health and the Environment (CDPHE) and the public for the utilization of a ground guy and durational limits on operations. The Commission argues that the use of a ground guy is in violation of relevant safety standards but nowhere in their opinion is this discussed and the record reflects that CDPHE recommended this as potential noise mitigation. AR 219. Further, the record does not reflect that the Commission considered limiting drilling hours to daytime operations.

Therefore, I find that Commission acted arbitrarily and capriciously in failing to consider the HVP technology as a potential BMP, and for failing to adequately explain why it was not feasible to have a tankless facility or follow the proposed noise mitigation measures of utilizing a ground guy or placing durational limits on drilling operations.

d. Access road

Plaintiffs argue that the approval of the Form 2A permit was arbitrary and capricious in their approval of a new access road. Specifically, Plaintiffs argue that the Commission did not

explain on the record how surface disturbance regulation was being met and the Commission erred in failing to respond to significant impacts on neighboring land uses and increased surface disturbance.

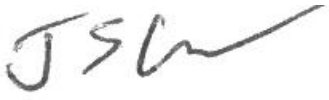
The maps provided in the record do not provide a clear picture of the proposed and actual access road in relation to abutting property owners. Interestingly, Neighbors argue that the disputed access road involved entirely new construction while the Industry argues that the access road was already in place and was simply widened in order to comply with Commission Rule 1002.e.(4).[2] I agree that oral argument would be helpful to the Court on this point.

IV. Conclusion

In summation, Neighbors have standing to pursue this lawsuit; the Commission is AFFIRMED as to the location of the production facilities; the Commission is REVERSED as to their best management practices and I will REMAND back to the board on that issue. Finally, as to the access road issue, I order the parties to confer and file a notice to set within three weeks of this order so the Court may entertain oral argument on this issue.

So Ordered.

Date: August 23, 2017



Jay S. Grant

District Court Judge

[2] "[e]xisting roads shall be used to the greatest extent practicable to avoid erosion and the land area devoted to oil and gas operations […] Where feasible and practicable, roads shall be routed to complement other land usage."

EXHIBIT C

FULLY REDACTED

EXHIBIT D

EXTRACTION OIL & GAS CONFIRMS DELIVERY OF AN OIL PIPELINE SOLUTION TO TRIPLE CREEK

DENVER – May 22, 2017 – Extraction Oil & Gas, Inc. (NASDAQ:XOG) today announced it has completed all comprehensive engineering, commercial and land use steps necessary to confirm that a crude oil pipeline solution will be implemented at its Triple Creek oil and gas development site ("Triple Creek") in Greeley, Colorado.

Completion of these steps, which included more than two years of engineering, third-party contracting, commercial and land acquisition work, delivers on the company's long-standing plan that a dedicated oil pipeline would be used to transport oil produced at Triple Creek to a regional crude oil terminal northeast of Greeley, Colorado. Utilizing oil pipeline gathering will additionally eliminate thousands of truck trips to and from the site that would have otherwise been needed to transport crude from Triple Creek. All oil volumes will be transported utilizing a federally regulated Department of Transportation-compliant pipeline that meets the highest safety standards for crude oil transportation.

"Because of our commitment to the community to plan a best-in-class project with minimal impacts, we are pleased to now confirm an oil pipeline solution will be used at this location," said Matthew Owens, president of Extraction Oil & Gas. "As we explained on many occasions, an oil pipeline solution has always been part of our plan for Triple Creek, but this was by no means an overnight process, and in fact, it took more than two years to secure all necessary components to announce confirmation of our pipeline plan," he said.

The company has been safely operating onsite at Triple Creek since January and drilling operations are currently ongoing utilizing an electric rig, which significantly reduces noise traditionally associated with drilling operations.

"Our industry-leading Triple Creek development is fully permitted and includes a record number of best management practices in its design," said Eric Jacobsen, senior vice president of operations. "Additionally, our safe and efficient operations have enabled us to reduce the estimated total time needed for development of this site by more than one year."

Extraction's Triple Creek project was designed as a top-tier energy development facility that will utilize many of the best technologies available to the onshore energy industry. Throughout its two-year planning process, the company engaged in the regulatory consultation process, working extensively with neighbors as well as state and local governments, to implement measures that will reduce and eliminate many of the impacts that might have otherwise resulted from the mineral development process. These advanced technologies include the use of an electric-powered drilling

rig, "ultra-quiet" completions fleet, electric-powered compression and extensive landscaping, among others.

Due to horizontal drilling technology utilized at its Triple Creek project, Extraction will also be able to remove and reclaim 10 legacy vertical wells located throughout Greeley. Nine of these wells are located approximately 300 feet from Aims Community College, and one legacy well is located approximately 125 feet from the Sheep Draw recreation trail.

"We are proud to remove older, vertical technology throughout the city while safely and responsibly accessing the energy we all need through newer, more consolidated engineering technology and designs," Jacobsen added. "Triple Creek is truly a blue-ribbon development, and we are pleased that it will soon be in the 'silent operations' phase of development while producing tax and royalty revenue for Aims Community College and many others over the next 25 to 30 years," he said.

About Extraction Oil & Gas, Inc.
Extraction is an independent oil and gas company focused on the acquisition, development and production of oil, natural gas and natural gas liquids reserves in the Rocky Mountains, primarily in the Wattenberg Field of the Denver-Julesburg Basin of Colorado. For more information about Extraction Oil & Gas, please visit www.extractionog.com

Cautionary Statement Concerning Forward-Looking Statements
Certain statements contained in this press release constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. These forward-looking statements represent Extraction's expectations or beliefs concerning future events, and it is possible that the results described in this press release will not be achieved. These forward-looking statements are subject to risks, uncertainties and other factors, many of which are outside of Extraction's control that could cause actual results to differ materially from the results discussed in the forward-looking statements.

Any forward-looking statement speaks only as of the date on which it is made, and, except as required by law, Extraction does not undertake any obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise. New factors emerge from time to time, and it is not possible for Extraction to predict all such factors. When considering these forward-looking statements, you should keep in mind the risk factors and other cautionary statements in the prospectus filed with the SEC in connection with Extraction's initial public offering and in subsequent public filings with the SEC. These and other factors could cause its actual results to differ materially from those contained in any forward-looking statement.

For additional information:

Media Contact:
Brian Cain, 281-825-2010
bcain@extractionog.com

EXHIBIT E

FULLY REDACTED

EXHIBIT F

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EXHIBIT G

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EXHIBIT O

Extraction Oil & Gas, Inc. Announces Southern DJ Basin Midstream Solution

July 9, 2018

DENVER, July 09, 2018 (GLOBE NEWSWIRE) -- Extraction Oil & Gas, Inc. (NASDAQ:XOG) (“Extraction”) today announced that it signed gathering agreements for oil, natural gas and water with Elevation Midstream, LLC (“Elevation”), a wholly-owned subsidiary of Extraction Oil & Gas, Inc. Elevation has secured financing for the build out of its system through GSO Capital Partners LP (“GSO”). This financing is non-recourse to Extraction.

Commenting on the transaction, Extraction’s Chairman and CEO Mark Erickson said: “We are extremely pleased to announce this transaction as we believe it is very beneficial to Extraction shareholders. While we will retain the full economic upside from this midstream system, the buildout will be fully financed without any expected cash outlay from Extraction. Once this midstream system is operational, we expect it will enhance our upstream value by driving significant reductions in lease operating expense and well cost, greater product capture and increased flow assurance while maintaining corporate differentials at or below current levels. It provides a potentially large value uplift for Extraction shareholders upon any eventual monetization of our midstream ownership. Additionally, the financing is non-recourse to Extraction which minimizes risk to our shareholders.”

Michael Zawadzki, Senior Managing Director and Co-Head of Energy at GSO said: “We are delighted to partner with Elevation on the construction of the Hawkeye and Southwest Wattenberg midstream systems. These facilities will allow Extraction and other third party customers to unlock highly attractive development opportunities in the infrastructure constrained southern DJ Basin.”

Updated Investor Presentation

Extraction has posted an updated investor presentation to its website. The investor presentation may be viewed on the Company’s website (www.extractionog.com) by selecting “Investors,” then “News and Events,” then “Presentations.”

About Extraction Oil & Gas, Inc.

Denver-based Extraction Oil & Gas, Inc. is an independent energy exploration and development company focused on exploring, developing and producing crude oil, natural gas and NGLs primarily in the Wattenberg Field in the Denver-Julesburg Basin of Colorado. For further information, please visit www.extractionog.com. The Company's common shares are listed for trading on the NASDAQ under the symbol: “XOG.”

About GSO Capital Partners

GSO Capital Partners LP is the global credit investment platform of Blackstone. With approximately $107 billion of assets under management, GSO is one of the largest alternative managers in the world focused on the leveraged-finance, or non-investment grade related, marketplace. GSO seeks to generate attractive risk-adjusted returns in its business by investing in a broad array of strategies including mezzanine debt, distressed investing, leveraged loans and other special-situation strategies. Further information can be found at https://www.blackstone.com/the-firm/asset-management/credit-(gso).

Cautionary Note Regarding Forward-Looking Statements

Certain statements contained in this press release constitute “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, included herein concerning, among other things, planned capital expenditures, increases in oil and gas production, the number of anticipated wells to be drilled or completed after the date hereof, future cash flows and borrowings, pursuit of potential acquisition opportunities, our financial position, business strategy and other plans and objectives for future operations, are forward-looking statements. These forward-looking statements are identified by their use of terms and phrases such as "may," "expect," "estimate," "project," "plan," "believe," "intend," "achievable," "anticipate," "will," "continue," "potential," "should," "could," and similar terms and phrases. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. These forward-looking statements represent our expectations or beliefs concerning future events, and it is possible that the results described in this press release will not be achieved. These forward-looking statements are subject to risks, uncertainties and other factors, many of which are outside of our control that could cause actual results to differ materially from the results discussed in the forward-looking statements.

Any forward-looking statement speaks only as of the date on which it is made, and, except as required by law, we do not undertake any obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise. New factors emerge from time to time, and it is not possible for us to predict all such factors. When considering these forward-looking statements, you should keep in mind the risk factors and other cautionary statements in the “Risk Factors” section of our most recent Form 10-K and Forms 10-Q filed with the Securities and Exchange Commission and in our other public filings and press releases. These and other factors could cause our actual results to differ materially from those contained in any forward-looking statement.

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Media Contact: Brian Cain, info@extractionog.com, 720-974-7782

Extraction Oil & Gas, Inc.

EXHIBIT P

FULLY REDACTED

EXHIBIT Q

FULLY REDACTED

EXHIBIT R

FULLY REDACTED

EXHIBIT S

FULLY REDACTED

EXHIBIT T

RESOLUTION NO. 2017-186

A RESOLUTION AUTHORIZING AND APPROVING AN AMENDED AND RESTATED OIL AND GAS OPERATOR AGREEMENT, A SURFACE USE AGREEMENT AND A SETTLEMENT AGREEMENT WITH EXTRACTION OIL & GAS, INC.

BE IT RESOLVED BY THE CITY COUNCIL OF THE CITY AND COUNTY OF BROOMFIELD, COLORADO:

Section 1. The Amended and Restated Oil and Gas Operator Agreement, the Surface Use Agreement, and the Settlement Agreement (the "Extraction Agreements"), all between The City and County of Broomfield and Extraction Oil and Gas, Inc., attached hereto, are hereby approved.

Section 2. The Mayor or Mayor pro tem is hereby authorized to sign and the City and County Clerk is authorized to attest the Amended and Restated Oil and Gas Operator Agreement, the Surface Use Agreement, and the Settlement Agreement, in form approved by the City and County Attorney.

Section 3. The City and County Manager is authorized to execute the agreements or approvals described within the Extraction Agreements as necessary to complete the formal transfer of certain property rights described within the form agreements set forth as exhibits or annexes to the Extraction Agreements, provided that said agreements or approvals are consistent with the terms of the Extraction Agreements and are approved as to form by the City and County Attorney.

Section 4. This resolution is effective upon its approval by the City Council.

APPROVED on October 24, 2017.

THE CITY AND COUNTY OF BROOMFIELD,
COLORADO

Mayor

ATTEST:

City and County Clerk

APPROVED AS TO FORM:

City and County Attorney Deputy

AMENDED AND RESTATED OIL AND GAS OPERATOR AGREEMENT

THIS AMENDED AND RESTATED OIL AND GAS OPERATOR AGREEMENT (the "Agreement") is made and entered into this 24th day of October, 2017, by and through Extraction Oil & Gas, Inc., 370 17th Street, Suite 5300, Denver, CO 80202 (the "Operator"), and the City and County of Broomfield, Colorado ("City") with an address of One DesCombes Drive, Broomfield, Colorado 80020, which may be collectively referred to herein as the "Parties", or individually as a "Party".

WHEREAS, Operator engages in the exploration, development, production and marketing of natural gas, oil and natural gas liquids, including in Broomfield, Colorado;

WHEREAS, Operator represents and warrants that, as of January 1, 2015, it is the successor-in-interest to Sovereign Operating Company, LLC ("Sovereign") with respect to those oil and gas operations subject to the Oil and Gas Operator Agreement, dated August 27, 2013, recorded at Reception No. 2013015088 (the "Operator Agreement");

WHEREAS, a Supplement to the Oil and Gas Operator Agreement was executed by the Parties on June 14, 2016, effective August 27, 2013, and recorded at Reception No. 2016007563. The Oil and Gas Operator Agreement and the Supplement to the Oil and Gas Operator Agreement is referred to herein as the "Operator Agreement, as Supplemented";

WHEREAS, the Parties agree that Operator's rights and duties set out in the Operator Agreement, as Supplemented have been and remain vested as determined by the Court in *Sovereign Operating Co. LLC v. City and County of Broomfield*, Case No. 2014CV30092 and that the Operator Agreement, as Supplemented remains in full force and effect;

WHEREAS, Operator is also the successor-in-interest to the Surface Use Agreement (the "SUA") between the City and Noble Energy, Inc., approved by the City on November 13, 2012, and recorded at Reception No. 2012014944 and is the successor-in-interest to a Use by Special Review Permit that was approved by the City on July 12, 2011 and recorded at Reception No. 2011006781;

WHEREAS, the Parties agree that the Parties each have rights and duties set forth in the SUA, which are also fully vested and may not altered or diminished without express agreement between the Parties;

WHEREAS, the City and Operator value a balanced approach to oil and gas development that is protective of public health, safety, and welfare, including the environment and wildlife

resources. To that end, in order to achieve those goals in a cooperative manner, the City and the Operator enter into this Agreement pursuant to Chapter 1-54 of the Broomfield Municipal Code ("BMC") allowing for this Agreement to adopt the best management practices set forth in Exhibit B (hereinafter referred to as "BMPs") for Operator's oil and gas operations at the Well Sites set forth on Exhibit A;

WHEREAS, Operator agrees to limit any New Wells to the Well Sites as set forth in Exhibit A;

WHEREAS, in accordance with state law and this Agreement, Operator commits to plug and abandon certain older wells in Broomfield that are described in Exhibit C;

WHEREAS, the Colorado Oil and Gas Conservation Act, C.R.S. § 34-60-101 *et. seq.* (the "Act"), authorizes the Colorado Oil and Gas Conservation Commission (the "COGCC" or the "Commission") to adopt statewide rules and regulations and amend existing rules and regulations or promulgate new rules and regulations;

WHEREAS, the Colorado Air Pollution Prevention and Control Act APPCA, C.R.S. § 25-7-128, authorizes the Colorado Department of Public Health and the Environment (the "CDPHE") to adopt emission control regulations for significant sources of air pollutants. CDPHE has promulgated specific emission control requirements for oil and gas facilities and it is anticipated that CDPHE will propose and adopt revisions to these requirements over time; and

WHEREAS, the APPCA, C.R.S. § 25-7-128, authorizes local governments to enact local air pollution resolutions or ordinances which may be the same as, or more restrictive than, state emission control regulations.

NOW THEREFORE, in consideration of the covenants and mutual promises set forth in this Agreement, including in the recitals, the Parties agree as follows:

1. Effective Date/Term. This Agreement will be effective upon City Council's approval by resolution and signature by both Parties (the "Effective Date"), and will continue in effect as long as the Operator has operations or owns or controls wells at the Well Sites or unless otherwise terminated by law (the "Term").

2. Prior Agreements. The Parties agree that Extraction's contract rights, as set forth in the Operator Agreement, as Supplemented, are vested as determined by Court Order, *Sovereign Operating Co. LLC v. City and County of Broomfield,* Case No. 2014CV30092. The Parties also agree that the SUA protects the City's property interests related to a proposed reservoir, as set

forth in the SUA. Without extinguishing the Parties' rights and obligations as set forth in the SUA and the Operator Agreement, as Supplemented, the Parties are amending and restating the rights and obligations of those two agreements in their entirety as set forth in this Agreement.

3. The City's Property Rights under the SUA. The Parties agree that the City owns property described in Exhibit 1 of the SUA, upon which the City proposes to construct a reservoir (the "Property"). Pursuant to paragraph 1 of the SUA, the Operator's surface use of the Property for any oil and gas operations is limited to the two locations set forth in the SUA. The Parties agree that those two locations will be replaced by the Livingston Pad set forth on Exhibit A. Any further change to the size or location of the Operator's surface use of the Property shall require the mutual consent of the Parties. Pursuant to paragraph 2 of the SUA, the Operator acknowledges and agrees that it has relinquished all drill site surface locations within the Property, except for the Livingston Pad. The Operator also agrees that it is bound by the Agreement Concerning Certain Mineral Rights, dated November 13, 2012, between Anadarko Land Corp. and the City.

4. New Wells and Well Sites. The Parties agree that the New Wells and the Well Sites will be subject to the terms of this Agreement. "New Well" shall mean any Operator-operated well spudded during the Term of this Agreement within the City, including any production facilities directly associated with such well, insofar as the production facilities and surface of the well are located on a surface location within the City limits, as constituted as of the date of this Agreement. For purposes of this Agreement, a New Well shall not include the re-entry of a previously drilled well. The Parties agree that Operator's future development of New Wells in the City will be limited to the six pad sites identified and depicted on Exhibit A (the "Well Sites"), and no New Wells will be drilled from the surface of any other area within the City. The Operator is responsible for obtaining surface use rights to all Well Sites. As long as Operator is in compliance with this Agreement, Operator may perform all surface and downhole well maintenance and operations on the New Wells and Wells Sites that the Operator deems prudent and necessary.

5. Limitation on Number Wells. The Operator agrees that it will drill no more than 84 New Wells on the Well Sites, up to a number of New Wells on each Well Site as follows: 19 New Wells on the Livingston Pad; 8 New Wells on the Northwest A Pad, 8 New Wells on the Northwest B Pad, 16 New Wells on the United Pad, 16 New Wells on the Interchange A Pad and 17 New Wells on the Interchange B Pad.

6. The Operator's Best Management Practices at the Well Sites. The Operator shall comply with all applicable state and federal laws and regulations. The Operator agrees to employ the BMPs on all New Wells and at all Wells Sites. The Operator agrees to include the BMPs on all

Applications for Permit-to-Drill, Form 2 ("Form 2"), and all Oil and Gas Location Assessments, Form 2A ("Form 2A"), submitted to the COGCC for any New Wells or Well Sites. The Parties agree that these BMPs, along with the requirements of this Agreement, meet the requirements of BMC section 17-54-200(A)(3) and that Operator has complied with the meeting and notice requirements of BMC section 17-54-200(B)(1) and (2).

7. Facilities. For any Facility owned by the Operator and existing prior to the Effective Date and located within the City limits, the Parties hereby agree that the Operator may perform maintenance or facility update operations on said Facility and perform such operations the Operator deems prudent and necessary. "Facility" for purposes of this Agreement shall include wells, flowlines, storage, metering, and all equipment necessary and appurtenant to such wells and pipeline. Operator agrees to conduct such operations as a prudent operator in accordance with the rules and regulations of the COGCC.

8. Plugging and Abandonment of Wells. In accordance with state law and this Agreement, Operator shall plug and abandon all of the wells shown on Exhibit C ("P&A Wells"). The Operator shall properly drain and decommission in accordance with City and COGCC rules and regulations all flowlines and pipelines associated with each P&A Well, unless the applicable surface owner or surface use agreement requires measures to be taken that differ from COGCC rules and regulations, and shall remove all facilities related to the P&A Wells. The plugging and abandoning of a particular P&A Well shall commence within sixty (60) days following the commencement of production from a New Well located in each of the drilling and spacing units encompassing the leasehold originally drilled by such P&A Well. The Operator shall conduct soil and, if encountered, groundwater testing after plugging and abandoning the P&A Well and submit the results to the City. The Operator shall remediate any contamination pursuant to COGCC regulations indicated by said soil and groundwater tests. Except as required by the BMPs, no further testing will be required unless remediation is required. Operator agrees that any well that Operator plugs and abandons, either before or after the Effective Date, may not be re-entered by Operator.

9. Comprehensive Drilling Plans and Applications. By no later than 30 days before the submission of a COGCC Form 2 and/or Form 2A for any New Well or Well Site, the Operator shall submit a Comprehensive Drilling Plan and Application for such New Wells or Well Sites for review and approval by the City. The Comprehensive Drilling Plan shall include the following, unless previously provided by the Operator to the City:

(A) A detailed site plan for all Well Sites that includes all documents required to be submitted with COGCC Form 2A, a depiction of all visible improvements within 500 feet of the proposed location, to include buildings, residences, public roads

and trails, major aboveground utilities, railroads, pipelines, mines, oil/gas/injection/water/plugged wells, water bodies, etc. as required by COGCC Rules, and the site plan requirements of the Broomfield Municipal Code, as amended;

(B) A site plan for site preparation, mobilization and demobilization;

(C) Project schedules for all phases, including site construction, pipeline construction, drilling, completions (broken down into activity-based components), commissioning, operations, reclamation and abandonment;

(D) A plan for interim reclamation and revegetation and final reclamation for all Well Sites;

(E) Noise Impact Mitigation Plan,

(F) Lighting Plan;

(G) A Traffic Management Plan;

(H) A list of permits requested, including any exceptions or variances that Operator is aware of needing at the time;

(I) Air Quality Impact Mitigation Plan;

(J) Emergency Response Preparedness Plan;

(K) Facility baseline surveys for air quality, noise and traffic;

(L) Facility emissions inventories and air quality impact studies for drilling, completions and operations phases, based upon proposed equipment use;

(M) Facility noise modeling of equipment proposed for the site for drilling, completions and operations phases;

(N) Hazardous Materials Management Plan;

(O) Waste Management Plan;

(P) Water Quality Plan;

(Q) Stormwater Management/Erosion Control Plan;

(R) Risk Management Plan;

(S) Grading, Drainage, Dust Mitigation, & Erosion Control Plan;

(T) Wetlands Protection Plan;

(U) Electrification Plan;

(V) Visual Mitigation Plan; and

(W) A summary of the outcome of the alternative site analysis.

All plans shall comply with the requirements set forth in Exhibit B. The Parties agree that Operator has had substantial engagement with the City with respect to its development plans. The Parties agree that, by submitting a Comprehensive Drilling Plan or Plans addressing all Well Sites, the Operator has complied with the City's administrative process and such Plans are subject to the City's administrative approval, which shall not be unreasonably withheld or delayed. At the time the Operator files any Form 2 or Form 2A for a New Well or Well Site, the

Operator will provide the City a copy of such filings and shall provide the City with notification of any decision with respect to any Form 2 or Form 2A for a New Well or a Well Site and Operator's best estimate as to when the Construction Phase for such New Well or Well Site will begin.

10. Development Schedule. The Operator has provided a summary of planned operations and operational timeline to the City. The Operator agrees that the first Well Site where drilling shall be conducted shall be at either the Interchange A Pad or the Interchange B Pad (the "Initial Well Site") and that at least eight (8) New Wells (the "Initial Wells") shall be drilled at such Well Site before drilling can commence at any other Well Site. The Operator also agrees that it will finish the Completion Phase for the Initial Wells before commencing the Completion Phase at any other Well Site. The Operator and City agree that Operator shall not be permitted to commence drilling at a Well Site later than December 31, 2022.

11. Approved Water Storage Site. "Approved Water Storage Site" means the Weber H Unit 1 Well Pad, which was approved by the City on February 12, 2013 for a use by special review permit by Resolution No. 2013-22. Operator is permitted to use the Approved Water Storage Site for fresh water storage. Fresh water will be transported via pipeline from the Approved Water Storage Site to each of the Well Sites for use during hydraulic fracturing and completions operations. The City will grant underground and surface pipeline right-of-way or licenses as necessary for the transportation of water to and from the Approved Water Storage Site. At the completion of Operator's plan of development, Operator will remove the water tanks and plug and reclaim the existing well at the Approved Water Storage Site in accordance with state law and regulations and the Broomfield Municipal Code.

12. City Administrative Approvals. The Operator shall not be required to obtain from the City Council any use by special review approvals or any other approvals for any New Wells subject to the terms and conditions of this Agreement, as long as the Operator complies with the terms and conditions contained herein. The City shall issue administrative approvals, by the City Manager or his designee, for the operations allowed for by this Agreement, in accordance with the procedures set forth in this Agreement and Chapter 17-54 of the Broomfield Municipal Code, if such operations comply with the requirements of this Agreement, including the BMPs set forth on Exhibit B. So long as the Operator complies with the terms and conditions of this Agreement, (i) the City agrees that it shall not protest, request a hearing, oppose or object in any forum to any permits, applications or similarly related approvals related to the Operator's oil and gas operations subject to this Agreement, (ii) the City shall provide written approvals and grant any waivers or variances that are reasonably requested by Operator related to the oil and gas operations subject to this Agreement, and (iii) Operator shall not be required to submit any minor variances or amendments to the proposed plan of operations so long as the Operator provides

notice to the City and such minor variances or amendments comply with the requirements of this Agreement, the Broomfield Municipal Code and COGCC rules and regulations.

13. Pipelines and Flowlines. The Operator agrees to utilize pipelines in accordance with Exhibit B (including Section 3 thereof), to be built in compliance with and using the specifications set forth on Exhibit D, at the locations set forth on Exhibit E as the "Pipeline Route". Operator shall provide the City with an as-built facilities map, as required by Section 19(B) of Exhibit B, which map shall automatically be incorporated into this Agreement and the Easement Grants, which form of agreement is attached as Exhibit F. Notwithstanding the foregoing, if after reasonable efforts the Operator and the City have not secured all right-of-way, crossings, common use agreements, easements or other similar rights (the "ROW") to utilize the Pipeline Route by February 15, 2018, the City shall provide or procure by March 1, 2018 the ROW necessary to connect "Point A" and "Point B" as depicted on Exhibit E, as well as all of the Well Sites, including by use of some or all of the "Acceptable Alternative Routes" set forth on Exhibit E. The Parties shall execute the necessary Easement Grants consistent with the form attached as Exhibit F in order to accomplish the foregoing.

Locations of flowline and pipeline easements may be changed by mutual written agreement of the City and Operator with each Party's consent not to be unreasonably withheld. The initial cost of installing pipelines and flowlines and of maintaining such easements shall be borne by the Operator. All costs and expenses of relocating pipelines and flowlines shall be borne by the Operator, unless such relocation is requested by the City, in which case the cost of the relocation of the pipeline or flowline shall be paid by the City. In the event that the City requests the relocation of a pipeline or flowline, the Operator shall provide the City with a written estimate of the relocation costs which the City shall thereafter remit within forty-five (45) calendar days from the date it receives the relocation cost estimate from the Operator. The payment shall be adjusted up or down, based on actual costs, upon completion of the work and after an itemized statement is provided to the City. In the event that Operator relocates an access road, pipeline or flowline causing damage to improvements owned by the City, the Operator shall promptly reimburse the City for such damage upon receipt of an itemized statement that documents the cost to repair the damage; provided that, such reimbursement shall be received by the City no later than forty-five (45) calendar days from the date of the itemized statement. If the City requests a relocation of a pipeline, the City will provide an alternative route to Operator and will grant the Operator the necessary time to construct and tie in to the new pipeline.

14. Surface Use. The Parties agree that the Surface Use Agreement, attached as Exhibit H, governs the Operator's use of the City's property, including access roads. Except as provided herein, these agreements replace any prior agreements with the City regarding surface use. The Parties shall execute the necessary Easement Grants consistent with the form attached as Exhibit

F. Operator shall comply with the applicable provisions of the Broomfield Standards and Specifications, as adopted by BMC section 14-04-010, with respect to those Broomfield Standards and Specifications that address public/private improvement permits and grading permits, as the same may be amended from time to time

15. Future Regulations. The City reserves the right in the future to enact and apply prospectively regulations that are general in nature and that are applicable to all commercial and industrial operations in the City, even though such regulations may be more or less stringent than the standards applicable to the Well Sites by virtue of this Agreement; provided that such regulations are not preempted by state law. Nothing in this Agreement affects the City's ability to in the future impose a transportation impact fee on the Operator, to the extent that such fees are applicable to all commercial transportation originating or terminating in the City.

16. Force Majeure. Neither Party will be liable for any delay or failure in performing under this Agreement in the event, and to the extent, that the delay or failure arises out of causes beyond a Party's control, including, without limitation, war, civil commotion, act of God, moratorium, ban, governmental act, strike or other stoppage (whether partial or total) of labor, any law, decree, regulation or order of any government or governmental body (including any court or tribunal), or inability to obtain permits, licenses, consents, easements, or rights of way, despite a Party's commercially reasonable efforts to fulfill its obligations under this Agreement. For purposes of this paragraph, the requirement that a Party exercise commercially reasonable efforts to fulfill its obligations includes using commercially reasonable efforts to anticipate any potential Force Majeure and commercially reasonable efforts to address the effects of any Force Majeure as it is occurring and following the potential Force Majeure, such that delay and any adverse effects of the delay are minimized to the greatest extent possible. For purposes of this Agreement, a "Force Majeure" does not include the financial inability, for any reason, to perform an obligation. A Party who asserts a claim of Force Majeure shall take all commercially reasonable measures to minimize the effects of such Force Majeure occurrence upon the Party's obligations under this Agreement. If any event occurs or has occurred that may cause a delay or failure in performance of an obligation under this Agreement for which a Party intends to assert a claim of Force Majeure, such Party shall give timely and reasonably detailed written notice and explanation to the other party of the Force Majeure event. It is agreed that, upon the affected Party's giving such notice to the other Party, the obligation of the Party giving such notice, so far as it is affected by such condition or event, shall be suspended and any time periods shall be extended for a period equal to the period of the continuance of the event or condition.

17. Authority to Execute Agreement. Each Party represents that the undersigned individuals have the full right and authority to enter into this Agreement and bind the Parties to the terms and

conditions contained herein. This Agreement may be amended only by an instrument executed by both Parties.

18. Assignment. Pursuant to Broomfield Municipal Code section 17-54-230, this Agreement may be assigned to another operator only with the prior written consent of the City Manager and upon a showing to the City that the Assignee can and will comply with all conditions and applicable provisions of the Agreement and all governing laws and regulations. Any assignment shall be on a form provided by the City and shall not be unreasonably withheld.

19. Successors and Assigns. The terms and conditions of this Agreement shall bind and extend to the City and the Operator, and the Operator's successors and assigns, and the Operator shall require any successor and assign, by written agreement, to adhere to all terms and conditions of this Agreement, and to expressly assume the defense and indemnity obligations to the City as set forth herein in a document acceptable in form to the City. Such assignment shall not relieve the assignee of any obligations that accrue during the period of operation of the assignee or otherwise arising out of the actions or inactions of the assignee during its period of operation. The Operator expressly agrees that this paragraph shall be a condition of the COGCC permit, and that failure to comply with this paragraph shall entitle the COGCC to revoke the permits for which ownership was assigned and shall entitle the City to revoke any approvals.

20. No Third Party Beneficiaries. Except for the rights of enforcement by the COGCC with respect to the BMPs, this Agreement is not intended to, and does not create, any right, benefit, responsibility or obligation that may be enforced by any non-party. Additionally, nothing in the Agreement shall entitle any third party to any claims, rights or remedies of any kind.

21. Notices. All notices and other correspondence related to this Agreement shall be in writing and shall be delivered by: (i) certified mail with return receipt, or (ii) hand delivery with signature or delivery receipt provided by a third party courier service (such as FedEx, UPS, etc.) to the designated representative of the Party as indicated below. A Party may change its designated representative for notice purposes at any time by written notice to the other Party. The initial representatives of the Parties are as follows:

City: **City & County of Broomfield**
One DesCombes Drive
Broomfield, CO 80020
Attn: City & County Manager
Telephone: 303-438-6300

Operator: **Extraction Oil & Gas, Inc.**
370 17th Street, Suite 5300
Denver, CO 80202
Attn: Legal Department
Telephone: 720-557-8300

22. Default and Remedies. If either Party notifies the other Party that it is in breach of the terms of this Agreement, including the attached Exhibits, such Party in alleged breach shall have a period of thirty (30) days from the date of such notice in which to remedy the alleged breach. If the alleged breach is of a nature that cannot be remedied within that 30-day period, such Party in alleged breach shall have commenced to remedy the breach and work diligently to complete the remedy. If (i) the Party in alleged breach fails to acknowledge that a breach has occurred or is occurring, (ii) following the process set forth in the previous two sentences the Party alleging breach believes that the other Party continues to be in breach of this Agreement, including the attached Exhibits, or (iii) any other kind of dispute arises under any provision of this Agreement that cannot be resolved by good faith negotiation between the Parties, the Party claiming that a breach of this Agreement has occurred or seeking resolution of any other dispute under this Agreement shall send written notice to the other Party, specifying its position in the matter and invoking the dispute resolution process in this section. Within fifteen (15) days of the date of delivery of such notice, the Parties shall meet to resolve the matter described in the notice. If either Party believes that mediation would be advantageous in connection with such meeting, or if a resolution of the matter cannot be achieved at the meeting, both parties agree to make a reasonable effort to work through and with a mutually acceptable mediator to attempt to resolve the dispute. Notwithstanding the foregoing, if either Party believes that the dispute will not otherwise be resolved in a sufficiently prompt and effective manner or if either Party determines that action is necessary for the protection of health, safety, welfare or the environment, such Party may, at its discretion, take such legal action and seek such legal or equitable remedies as it determines to be appropriate or necessary to protect and enforce its rights under this Agreement. Such remedies may include, without limitation, an injunction to stop an alleged violation or an order requiring the performance by the other Party, or other remedies permitted under law or this Agreement. The City does not waive its right to seek enforcement under the Broomfield Municipal Code for a breach that Operator has remedied under this provision.

23. Defense and Indemnity. Operator agrees to defend and indemnify the City, its employees, boards, agents and City Council (collectively "City Entities") from and against all claims and liability against the City Entities arising out of or related to the operations of the Operator at the Well Sites and any action or inaction of the Operator at or in connection with the Well Sites, including but not limited to claims for bodily injury, death, property or other damage, remediation or other costs, or claims under any local, state or federal environmental law. As

used in this paragraph, the term "claim" means any claim filed in any judicial or administrative forum and any administrative proceeding or order. This defense and indemnity does not apply to a claim or liability that arises from the negligence or willful misconduct of the City Entities. The obligations of this paragraph shall survive the termination of this Agreement.

24. Integration Clause. This Agreement, along with all exhibits attached, the Settlement Agreement dated the date hereof between the City and Operator and the New SUA, hereto encompass the entire agreement of the Parties and, except as otherwise provided herein, supersedes all previous understandings and agreements between the Parties, whether oral or written, including the Operator Agreement, as Supplemented and the SUA.

25. Conflicts. In the event that conflicts exist within the terms and conditions of this Agreement and the attached Exhibits and/or referenced prior agreements, this Agreement shall control.

26. Governing Law. This Agreement shall be governed and construed in accordance with the laws of the State of Colorado without reference to its conflicts of laws provisions.

27. Enforcement. The Parties understand and agree that the City may enforce violations of this Agreement under Chapter 17-54, as amended, of the Broomfield Municipal Code.

28. Insurance. The Operator agrees to provide insurance under the conditions, and in the amounts, set forth on Exhibit G.

29. Severability.

a. If any part of this Agreement is found to be in conflict with applicable laws, such part shall be inoperative, null and void insofar as it conflicts with such laws; however, the remainder of this Agreement shall be in full force and effect.

b. In the event that any part of this Agreement would otherwise be unenforceable or in conflict with applicable laws due to the term or period for which such part is in effect, the term or period for which such part of this Agreement shall be in effect shall be limited to the longest period allowable which does not cause such part to be unenforceable or in conflict with applicable laws.

c. If any section, paragraph, provision, or portion thereof of this Agreement is held by any Court to be void and/or unenforceable for any reason, such section, paragraph, provision, or portion thereof shall be excised from the Agreement and shall be replaced with terms and

provisions that are most consistent with, and which reflect, the Parties' intention. All remaining sections, paragraphs, provisions, or portions thereof shall remain in full force and effect.

30. No Presumption. The Parties to this Agreement and their attorneys have had a full opportunity to review and participate in the drafting of the final form of this Agreement. Accordingly, this Agreement shall be construed without regard to any presumption or other rule of construction against the Party causing the Agreement to be drafted.

31. Amendments. No changes, alterations or modifications to any of the provisions set forth in this Agreement shall be effective unless contained in a written agreement signed by both Parties.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by a duly authorized representative on the day and year first written above.

THE CITY:

THE CITY AND COUNTY OF BROOMFIELD, COLORADO
A Colorado Municipal Corporation and County

Mayor

CITY & COUNTY OF BROOMFIELD SEAL COLORADO

ATTEST:

City & County Clerk

APPROVED AS TO FORM:

City & County Attorney Deputy

THE OPERATOR:

EXTRACTION OIL & GAS, INC.

Eric J. Christ, Vice President, General Counsel & Corporate Secretary

STATE OF COLORADO)
) ss
COUNTY OF Broomfield)

The foregoing instrument was acknowledged, subscribed and sworn to before me this 25th day of October, 2017, by _____.

[SEAL]

LINDA J. VILLAREAL
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20134063200
My Commission Expires Oct. 7, 2021

Notary Public

My Commission Expires: October 7, 2021

List of Exhibits

Exhibit A - Maps of the Well Sites

Exhibit B – List of BMPs

Exhibit C – List of P&A Wells

Exhibit D - Pipeline Requirements

Exhibit E - Pipeline Route (Map)

Exhibit F - Form of Easement Grant

Exhibit G - Insurance Requirements

Exhibit H - Surface Use Agreement

Exhibit I - Potential Locations for Berms, Bales or Sound Walls

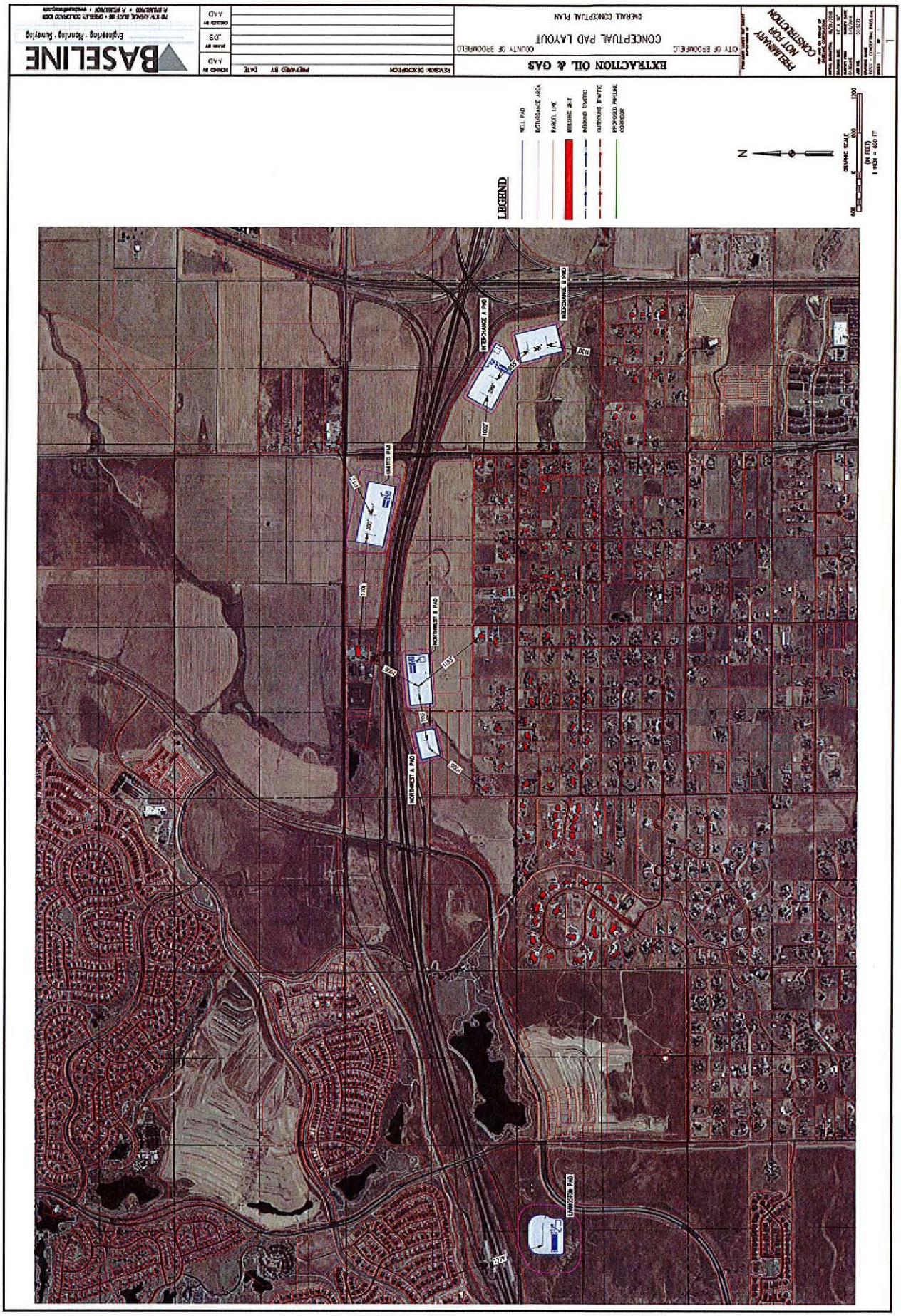


EXHIBIT A

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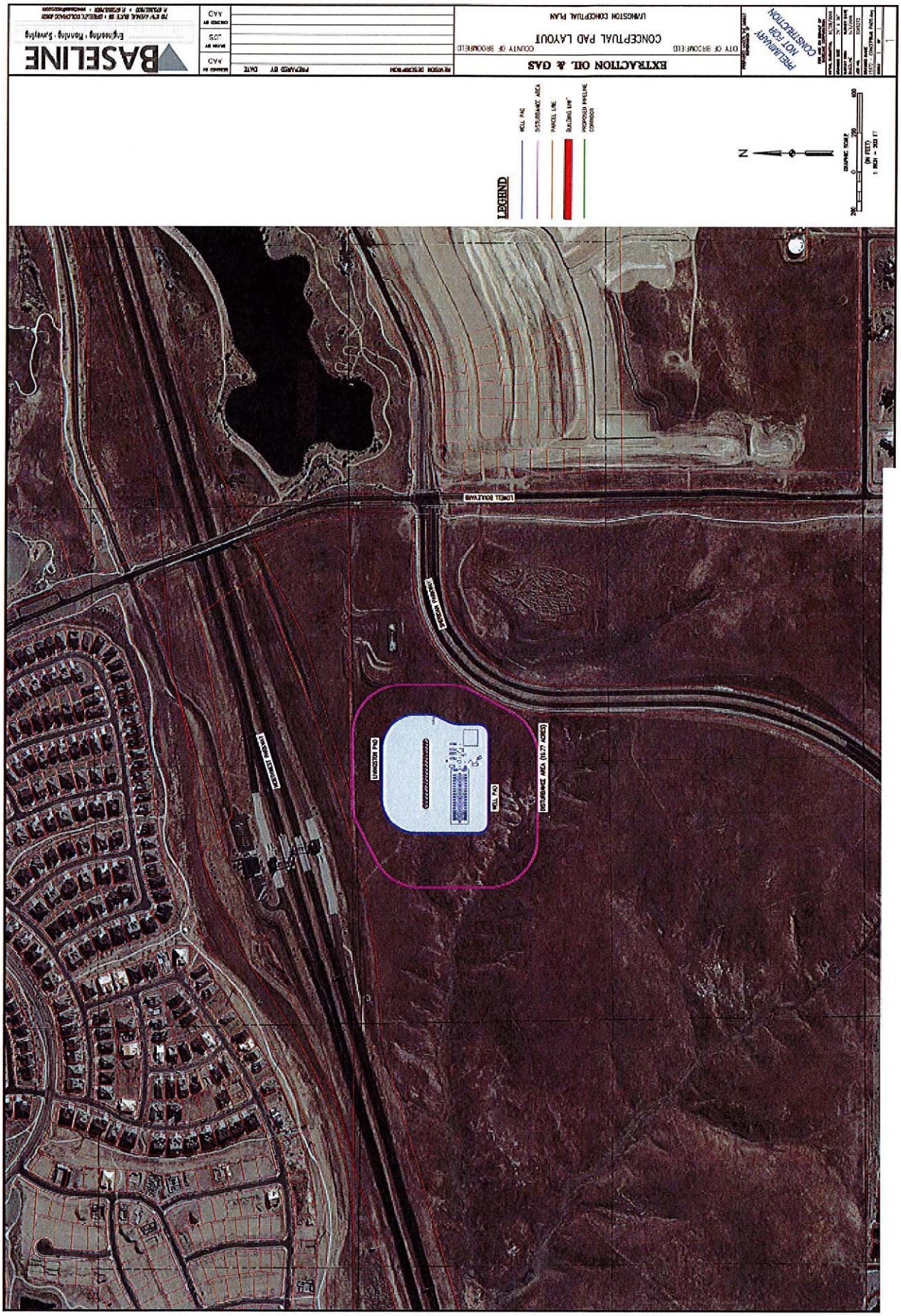


EXHIBIT A

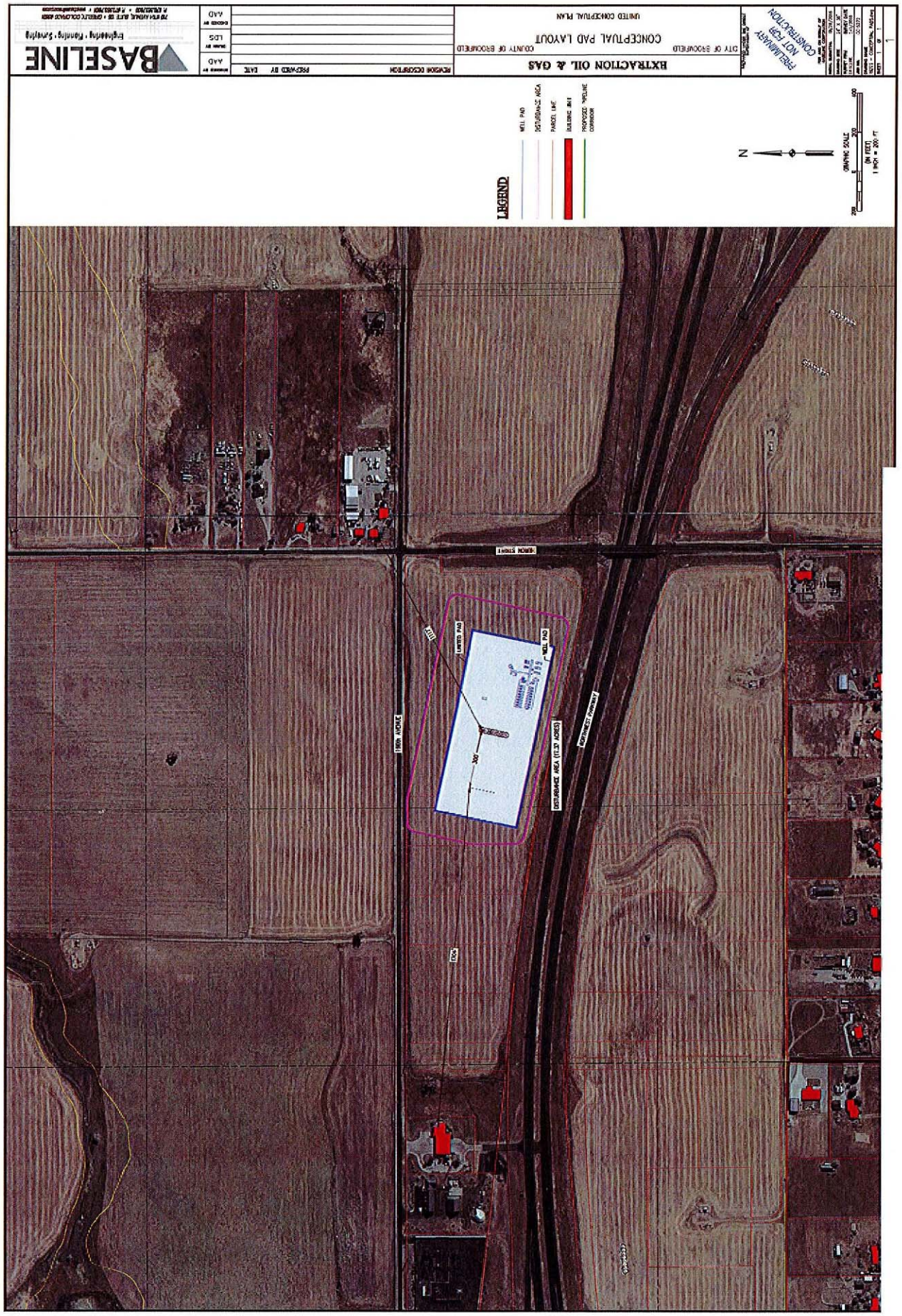
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EXHIBIT A

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EXHIBIT A

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EXHIBIT B

BEST MANAGEMENT PRACTICES FOR WELL SITES AND NEW WELLS AT WELLS SITES

Operator shall include the BMPs listed in this Exhibit B on all Applications for Permit-to-Drill, Form 2 ("Form 2"), and Oil and Gas Location Assessments, Form 2A ("Form 2A"), submitted to the Commission for a "New Well" on the Well Sites. For the purposes of this provision, "New Well" shall mean any Operator-operated well spudded during the term of this Agreement, and located on the Well Sites, including any production facilities directly associated with such well, and its associated Well Pad, insofar as it covers lands located in the City limits. The BMPs shall apply to all New Wells drilled by the Operator on the Well Sites, while this Agreement is effective. The re-entry of a previously plugged and abandoned well is not allowed.

1. *Well Sites*. The Operator agrees that the maximum number of New Wells to be drilled at each of the Well Sites set forth on Exhibit A shall be as follows:

- Livingston Pad – 19 New Wells;
- Northwest A Pad – 8 New Wells;
- Northwest B Pad – 8 New Wells;
- United Pad – 16 New Wells;
- Interchange A Pad – 16 New Wells; and
- Interchange B Pad – 17 New Wells.

For purposes of this Agreement, the phases of operation at a Well Site shall be defined as follows:

"Construction Phase" shall mean the conducting of civil and earth work in connection with the construction and installation of drilling pads, visual mitigation measures, access routes, pipelines and launcher/receiver locations.

"Drilling Phase" shall mean the period in which a drilling rig is utilized to penetrate the surface of the earth with a drill bit and the installation of well casing and cement at one or more wells.

"Completion Phase" shall mean the period of hydraulic fracturing, coiling, workover, installation of tubing and flowback of one or more wells.

"Production Phase" shall mean the period in which one or more wells is capable of producing hydrocarbons that flow through permanent separator facilities and into the pipeline gathering system.

For the avoidance of doubt, it is possible for multiple phases of operation to be occurring at the same time with respect to a single Well Site. Notwithstanding the

foregoing, Operator agrees that it will not conduct hydraulic fracturing and drilling operations simultaneously at a single Well Site.

2. *Quiet Technology*. The Operator agrees to use the Liberty Quiet Fleet or comparable technology from an alternative vendor on all Well Sites.

3. *Use of Pipelines*. The Operator agrees to build pipelines for the transport of oil, gas, and produced water from the Well Sites to the specifications set forth in Exhibit D and to utilize such pipelines at the Well Sites before the Production Phase commences. During the Completion Phase, the Operator will use pipelines for produced water for flowback to the maximum extent feasible. All fresh water shall be transported to the Well Sites by means other than by truck. The Operator's obligation to build and utilize such pipelines is subject to the City granting Operator all necessary right-of-way and the City issuing Operator the necessary Public/Private Improvement Permits. Operator shall be permitted to utilize temporary tanks during drilling, flowback, workover, completion, hydraulic fracturing and maintenance operations. If requested by the City, Operator will conduct a risk analysis to identify potential risks associated with pipelines and the measures implemented that are intended to mitigate such risks.

4. *Air Modeling Study*. The Operator has completed an air modeling study that meets the standards requested by the City and such study has been conducted and indicates that emissions from the equipment proposed on the Well Sites meets EPA standards.

5. *Regulations*. The Operator shall comply with all applicable state, and federal regulations in addition to the terms of this Agreement and the BMPs set forth in this Exhibit B. The City agrees that it will not impose any fine on the Operator for violation of this Agreement if the activity or condition that created the violation is also subject to regulation by the COGCC, and if the violation results in action taken by the COGCC against the Operator.

6. *Notification to the City Regarding Commencement of Operations*. Operator shall provide written notice to the City no less than thirty (30) days prior to the commencement of any of the following: Construction Phase (unless the Construction Phase commences within 45 days of the approval of the applicable Form 2 or Form 2A), Drilling Phase, Completion Phase, or any recompletion, re-drilling or plugging and abandonment of a New Well. Any notification provided by Operator to City pursuant to this Agreement may be used by the City for public notification.

7. *Inspections*. The City shall have the right to have the City's designated oil and gas inspector (the "Inspector") inspect the Well Sites, upon reasonable notice to the Operator and the Operator shall provide a safety escort to accompany the Inspector. Reasonable notice may include notification by the Inspector at the Well Site. If the Inspector notifies the Operator of any conditions that the Inspector believes are out of compliance with this Agreement, Operator shall promptly address such conditions. If the Operator disagrees

with the findings of the Inspector, the City and Operator shall resolve the disagreement consistent with the provisions set forth in Section 22 of the Agreement.

8. *Containment Berms*. The Operator shall utilize steel-rim berms around all permanent facility equipment at the Well Sites with sufficient capacity to contain 1.5 times the maximum volume of liquids that such facility will contain at any given time plus sufficient freeboard to prevent overflow. All berms and containment devices shall be inspected quarterly by the Operator and maintained in good condition. No potential ignition sources shall be installed inside the secondary containment area unless the containment area encloses a fired vessel or such sources are rated in accordance with industry codes and standards. Secondary containment such as duck ponds or lined earthen berms for temporary tanks shall also be used.

   A. Permanent containment berms shall be constructed of steel rings, designed and installed to prevent leakage and resist degradation from erosion or routine operation.

   B. Secondary containment for tanks shall be constructed with a synthetic or engineered liner that contains all primary containment vessels and is mechanically connected to the steel ring to prevent leakage.

   C. For locations within five hundred (500) feet and up-gradient of a surface water body, tertiary containment, such as an earthen berm, is required around production facilities.

9. *Closed-Loop Pitless Systems for the Containment and/or Recycling of Drilling Fluids.* Wells shall be drilled, completed and operated using closed-loop pitless systems for containment and/or recycling of all drilling, completion, flowback and produced fluids. Operator shall recycle fluids to the maximum extent practicable, with the understanding that Operator is limited in its ability to recycle all fluids, as doing so would necessitate the use of permanent tanks, which is otherwise prohibited by the terms of the Agreement, and result in the potential for additional emissions. Other than for irrigating landscape material, Operator shall not use City water for any of its oil and gas operations. Operator shall not store waste onsite for periods longer than 30 days.

10. *Anchoring.* All New Well equipment and all existing equipment at the Well Sites shall be anchored to the extent necessary to resist flotation, collapse, lateral movement, or subsidence in compliance with applicable Federal Emergency Management Agency (FEMA) (as administered by this City) and COGCC rules and regulations.

    All guy line anchors left buried for future use shall be identified by a marker of bright color not less than four (4) feet in height and not greater than one (1) foot east of the guy line anchor.

11. *Burning.* No open burning shall occur on the site of any oil and gas operation.

12. *Chains.* Traction chains from heavy equipment shall be removed before entering a City street.

13. *Chemical Disclosure and Storage.* All fracturing chemicals must be disclosed to the City pursuant to the process set forth below before bringing on site. Prior to the bringing of such chemicals onto the property, the Operator shall make available to the City, in table format, the name, Chemical Abstracts Service (CAS) number, storage, containment and disposal method for such chemicals to be used on the Well Sites, which the City may make available to the public as public records. Fracturing chemicals shall be uploaded onto the Frac Focus website within sixty days of the completion of fracturing operations. The Operator shall not permanently store fracturing chemicals, flowback from hydraulic fracturing, or produced water in the City limits. Operator shall remove all hydraulic fracturing chemicals at a Well Site within thirty (30) days following the completing of hydraulic fracturing at that Well Site.

In addition to any substances that not permitted to be used in accordance with state or federal rules or regulations in place from time to time, the following chemicals shall not be utilized in hydraulic fracturing fluid at the Well Sites:

Ingredient Name	**CAS #**
Benzene	71-43-2
Lead	7439-92-1
Mercury	7439-97-6
Arsenic	740-38-2
Cadmium	7440-43-9
Chromium	7440-47-3
Ethylbenzene	100-41-4
Xylenesf	1330-20-7
1,3,5-trimethylbenzene	108-67-8
1,4-dioxane	123-91-1
1-butanol	71-36-3
2-butoxyethanol	111-76-2

N,N-dimethylformamide	68-12-2
2-ethylhexanol	104-76-7
2-mercaptoethanol	60-24-2
benzene, 1,1′-oxybis-, tetrapropylene derivatives, sulfonated, sodium salts (BOTS)	119345-04-9
butyl glycidyl ether	8/6/2426
polysorbate 80	9005-65-6
quaternary ammonium compounds, dicoco alkyldimethyl, chlorides (QAC)	61789-77-3
bis hexamethylene triamine penta methylene phosphonic acid (BMPA)	35657-77-3
diethylenetriamine penta (methylene-phosphonic acid)(DMPA)	15827-60-8
FD&C blue no. 1	3844-45-9
Tetrakis(triethanolaminato) zirconium(IV) (TTZ)	101033-44-7

14. *Color*. Permanent facilities shall be painted in a uniform, non-contrasting, non-reflective color, to blend with the surrounding landscape and, with colors that match the land rather than the sky, consistent with COGCC regulations. If the City desires a specific color or colors, it shall notify Operator of such color or colors prior to the Pad Construction of a Well Site and Operator shall utilize such color or colors.

15. *Cultural and Historical Resource Protection*. The Operator has completed a site assessment and is not currently aware of any historical or cultural sites on the Well Sites. However, if a significant surface or sub-surface archaeological site is discovered during construction, the Operator shall be responsible for immediately contacting the City to report the discovery. If any disturbance of a site deemed by the State Historic Preservation Office to be a historical or cultural resource occurs, the Operator shall be responsible for mitigating the disturbance to the cultural or historical property through a data recovery plan in consultation with the City's Historic Landmark Board and the State Historic Preservation Office, with copy to the City.

16. *Discharge Valves*. Open-ended discharge valves on all storage tanks, pipelines and other containers within the Well Site shall be secured and shall not be accessible to the general

public. Open-ended discharge valves within the Well Site shall be placed within the interior of the secondary containment area.

17. *Fugitive Dust Suppression.* Dust associated with on-site activities and traffic on access roads shall be minimized throughout construction, drilling and operational activities such that there are no visible dust emissions from access roads or the Well Sites to the extent practical given wind conditions. No untreated produced water or other process fluids shall be used for dust suppression. The Operator will avoid creating dust or dust suppression activities within three hundred (300) feet of the ordinary high water mark of any waterbody, unless the dust suppressant is water. Material Safety Data Sheets (MSDS) for any chemical based dust suppressant, other than magnesium chloride, shall be submitted to the City prior to use. Operator must submit to the City a grading, drainage, dust mitigation and erosion control plan in accordance with Section 37.

18. *Electric Equipment.* The drilling rig(s) used during the Drilling Phase and all permanent production equipment, such as compressors, motors and pump jacks, shall utilize electric line power in order to mitigate noise and to reduce emissions.

19. *Emergency Preparedness Plan.* The Operator is required to complete a detailed Emergency Plan in accordance with the provisions of this Section, and Operator shall pay for any reasonably necessary training and equipment of emergency response personnel specifically required due to the operations contemplated by this Agreement, including any inventory of Aqueous film forming foam (AFFF) required to be purchased from time to time so that sufficient quantities are on-hand to respond to emergencies on the Well Sites. The City and the North Metro Fire Rescue District must approve of the Emergency Plan before the Drilling Phase commences. As long as all requirements of this Section are met, the City and the North Metro Fire Department shall not unreasonably withhold approval and shall approve the Emergency Plan within thirty (30) days of submittal.

The Emergency Plan shall be filed with the City and the North Metro Fire Rescue District and updated on an annual basis or as conditions change (responsible field personnel change, ownership changes, etc.). The Emergency Plan shall include a notification system for potentially affected citizens and occupied buildings and an evacuation plan.

The Emergency Plan shall consist of at least the following information:

A. Name, address and phone number, including twenty-four (24)-hour emergency numbers for at least two persons responsible for emergency field operations as well as the contact information for any subcontractor of Operator engaged for well-control emergencies.

B. An as-built facilities map in a format suitable for input into the City's GIS system depicting the locations and type of above and below ground facilities, including sizes and depths below grade of all oil and gas flow lines and associated equipment, isolation valves, surface operations and their functions, as well as transportation routes to and from exploration and development sites, for

emergency response and management purposes. The information concerning flowlines and isolation valves shall be held confidentially by the City and shall only be disclosed in the event of an emergency or to emergency responders or for the training of emergency responders. The City shall deny the right of inspection of the as-built facilities maps to the public pursuant to C.R.S. § 24-72-204.

C. Detailed information addressing each reasonable potential emergency that may be associated with the operation. This may include any or all of the following: explosions, fires, gas, oil or water pipeline leaks or ruptures, hydrogen sulfide or other toxic gas emissions, or hazardous material vehicle accidents or spills. A provision that any spill outside of the containment area, that has the potential to leave the facility or to threaten waters of the state, or as required by the City-approved Emergency Plan shall be reported to the local emergency dispatch and the COGCC Director in accordance with COGCC regulations.

D. Detailed information identifying access or evacuation routes, and health care facilities anticipated to be used.

E. A project-specific plan for any project that involves drilling or penetrating through known zones of hydrogen sulfide gas.

F. A statement and detailed information indicating that the Operator has adequate personnel, supplies, and training to implement the Emergency Plan immediately at all times during construction and operations.

G. The Operator shall have current Material Safety Data Sheets (MSDS) for all chemicals used or stored on a site. The MSDS sheets shall be provided immediately upon request to City officials, a public safety officer, or a health professional as required by COGCC Rule 205.

H. The Emergency Plan shall include a provision establishing a process by which the Operator notifies surrounding neighbors to inform them about the on-site operations and provide sufficient contact information for surrounding neighbors to communicate with the Operator.

I. All training associated with the Emergency Plan shall be coordinated with the City and the North Metro Fire Rescue District.

J. A provision obligating the Operator to reimburse the appropriate emergency agencies for their expenses resulting from the Operator's operations, to the extent required by Colorado State Statutes.

K. Operator shall provide the City with its emergency shutdown protocols and promptly notify the City of any emergency shut downs that would have an impact to any area beyond the confines of the Well Site.

20. *Air Quality*. In order to minimize degradation to air quality, Operator agrees to the provisions set forth in this Section. Operator must eliminate, capture, or minimize all potentially harmful emissions and minimize dust associated with onsite activities and traffic on access roads pursuant to the terms of this Agreement. Operator shall comply with all applicable state and federal regulations including regulations promulgated by CDPHE, COGCC and US EPA.

A. Minimization of Emissions.

To protect air quality, the following will be required:

1. The use of electric equipment and line power, as detailed in Section 18.
2. The use of Tier 2 and liquefied natural gas dual fuel hydraulic fracturing pumps. If Tier 4 fracturing pumps become commonly available, Operator will begin using Tier 4 fracturing pumps.
3. Comply with traffic provisions set forth in Section 40. Limitations on truck traffic to and from the site.
4. The utilization of pipelines pursuant to Section 3.
5. Manufacture test or other data demonstrating hydrocarbon destruction or control efficiency that complies with a design destruction efficiency of 98% or better.
6. The use of no-bleed continuous and intermittent pneumatic devices. This requirement can be met by replacing natural gas with electricity or instrument air, or routing the discharge emissions to a closed loop-system or process.
7. Any flare, auto ignition system, recorder, vapor recovery device or other equipment used to meet the hydrocarbon destruction or control efficiency requirement shall be installed, calibrated, operated, and maintained in accordance with the manufacturer's recommendations, instructions, and operating manuals.
8. No use of glycol dehydrators.
9. No use of desiccant gas processing dehydrators.
10. Year-round application of odor requirements pursuant to COGCC and CDPHE regulations.
11. Reduction or elimination of emissions of associated gas from hybrid gas-oil wells (i.e. gas that is co-produced from a well that primarily produces oil), including prohibition of uncontrolled venting.

12. Best management practices during liquids unloading (i.e. maintenance activities to remove liquids from existing wells that are inhibiting production), including at least 90% emissions reduction when utilizing combustion and the installation of artificial lift or unloading through the separator where feasible.

13. Reduction or elimination of emissions from oil and gas pipeline maintenance activities such as pigging or blowdowns. If any maintenance activity will involve the intentional venting of gas from a well tank, compressor or pipeline, beyond routine pipeline maintenance activity and pigging, the operator shall provide forty eight (48) hour advance written notice to the City of such proposed venting. Such notice shall identify the duration and nature of the venting event, a description as to why venting is necessary, a description of what vapors will likely be vented, what steps will be taken to limit the duration of venting, and what steps the operator proposes to undertake to minimize similar events in the future. If emergency venting is required, or if accidental venting occurs, the operator shall provide such notice to the City of such event as soon as possible, but in no event longer than 24 hours from the time of the event, with the information listed above and with an explanation as to the cause and how the event will be avoided in the future.

14. Compliance with dust suppression techniques set forth in Section 17.

15. Compliance with odor requirements set forth in Section 48.

16. Consolidation of product treatment and storage facilities within a Well Site.

17. Centralization of compression facilities within a Well Site.

18. Telemetric control and monitoring systems, including surveillance monitors to detect when pilot lights on control devices are extinguished.

19. Operator will comply with all CDPHE air permits, if any, and will comply with all OSHA work practice requirements with respect to benzene.

20. Flaring shall be eliminated or minimized to the maximum extent practicable.

21. Exhaust from all engines, motors, coolers, and all other equipment must be vented up and away from nearest residences.

22. Operator agrees to participate in Natural Gas STAR program or other voluntary programs to encourage innovation in pollution control at well sites.

23. Use of a pressure-suitable separator and vapor recovery unit (VRU) where applicable.

24. Pipeline infrastructure will be constructed prior to the Production Phase.

B. *Leak Detection and Repair*. Operator shall develop and maintain an acceptable leak detection and repair ("LDAR") program as required by CDPHE using modern leak detection technologies such as infra-red cameras for equipment used on the Well Sites. For the five (5) year period beginning with the start of the Drilling Phase at the first Well Site, Operator shall conduct quarterly IR camera monitoring of all equipment at the Well Sites. When an IR camera is used, Operator must retain an infrared image or video of all leaking components before and after repair. Such records must be maintained for two years and must be made available to the City upon request. Except when an emergency circumstance would necessitate an immediate repair, Operator must repair leaks as quickly as practicable. If more than 48-hours repair time is needed after a leak is discovered, an explanation of why more time is required must be submitted to the City. Operator shall conduct continuous pressure monitoring to detect leaks. At least once per year, the Operator shall notify the City five (5) business days prior to an LDAR inspection of its facilities to provide the City the opportunity to observe the inspection.

C. *Ambient Air Sampling*. The Operator shall conduct, as approved by the City, a specific ambient air quality test that includes:

1. Pre-construction baseline air quality testing shall be completed within 500 feet of the Well Sites by a consultant approved by the City and paid for by the Operator.
2. Operator agrees to provide the City $20,000 annually towards air quality sampling. The City may use these funds for sampling within its discretion. Extraction will provide initial funds prior to the Construction Phase. Such amount shall be adjusted each year by the increase or decrease in the Consumer Price Index issued by the United States Bureau of Labor Statistics for the Denver – Boulder metropolitan area.
3. In addition, the City may require the Operator to conduct additional air monitoring as needed to respond to emergency events such as spill, process upsets, or accidental releases.
4. Operator shall provide access to the Well Sites to the City's designated inspector to allow air sampling to occur.

An air modeling and emissions inventory based upon the proposed development and equipment have been completed by a third-party consultant.

D. *Air Quality Action Days*. The Operator shall respond to air quality Action Day advisories posted by the Colorado Department of Public Health and Environment for the Front Range Area by implementing their suggested air emission reduction measures as feasible. Emission reduction measures shall be implemented for the duration of an air quality Action Day advisory and may include measures such as:

1. Minimize vehicle and engine idling;
2. Reduce truck traffic and worker traffic;
3. Delay vehicle refueling;
4. Suspend or delay use of fossil fuel powered ancillary equipment; and
5. Postpone construction activities, if feasible.
6. Within 30 days following the conclusion of each annual Air Quality Action Day season, Operator must submit a report to the City that details which measures it implemented during any Action Day advisories.

E. *Compliance.* The Operator must submit annual reports to the City certifying (a) compliance with these air quality requirements and documenting any periods of material non-compliance, including the date and duration of each such deviation and a compliance plan and schedule to achieve compliance, (b) that the equipment at the Well Sites continues to operate within its design parameters, and if not, what steps will be taken to modify the equipment to enable the equipment to operate within its design parameters. The annual report must contain a certification as to the truth, accuracy and completeness of the reports, signed by a responsible corporate official. The Operator may satisfy this reporting obligation in whole or in part by submitting its AQCC Regulations No. 7 annual reports for the prior calendar year to the City, and supplementing them as needed to meet these reporting requirements for covered facilities within the City. The Operator will also provide the City will a copy of any self-reporting submissions that Operator provides to the CDPHE due to any incidence of non-compliance with any CDPHE air quality rules or regulations at the Well Sites.

21. *Reduced Emission Completions (Commonly known as Green Completions).* At Well Sites Operator shall employ reduced emission completions, also commonly known as green completions, which comply with federal and state requirements. In addition, Operator shall comply with the following:

A. Gas gathering lines, separators, and sand traps capable of supporting green completions as described in COGCC Rule 805 shall be installed per the provisions of COGCC Rule 805.

B. Operator shall comply with 40 CFR 60.5375(a)(1), (2) for green completions.

C. Uncontrolled venting is prohibited other than where necessary for safety.

D. Temporary flowback flaring and oxidizing equipment where allowed shall include the following:

1. Adequately sized equipment to handle 1.5 times the largest flowback volume of gas from a vertical/directional and/or horizontally completed well respectively as reported to the COGCC in a ten mile radius;

2. Valves and porting available to divert gas to flaring and oxidizing equipment; pursuant to the above Rules 40 CFR 60.5375 & COGCC Rule 805;

3. Auxiliary fueled with sufficient supply and heat to combust or oxidize non-combustible gases in order to control odors and hazardous gases. The flowback combustion device shall be equipped with a reliable continuous ignition source over the duration of flowback, except in conditions that may result in a fire hazard or explosion; and

4. The Operator has a general duty to safely maximize resource recovery and minimize releases to the atmosphere during flowback and subsequent recovery/operation.

22. *Exhaust.* The exhaust from all engines, motors, coolers and other mechanized equipment shall be vented up or in a direction away from the nearest occupied building.

23. *Fencing.* Permanent perimeter fencing shall be installed around production equipment unless such fencing is not required by the Visual Mitigation Plan for a Well Site , and shall be secured. The main purpose of the fencing is to deter entrance by unauthorized people and a Well Site shall be properly secured prior to the commencement of drilling at the Well Site. The Operator shall use visually interesting fencing, when feasible, but the parties recognize that there is a need for air circulation, and for the field personnel who regularly inspect the facilities to be able to identify visual operational deficiencies when driving by. Landscaping may be used for screening. If a chain link fence is required to achieve safety requirements set by the COGCC, then landscaping and other screening mechanisms shall be required that comply with the City's Land Use Code regulations and the Operator's safety requirements.

24. *Flammable Material.* All ground within twenty-five (25) feet of any tank, or other structure containing flammable or combustible materials, shall be kept free of dry weeds, grass or rubbish, and shall conform to COGCC 600 Series Safety Regulations and the applicable Fire Code.

25. *Flares and Combustion Devices.* To the extent flares, thermal oxidizers, or combustion devices are utilized, all such flares shall be designed and operated as follows:

A. The flare must be fired with natural gas and designed to operate with a 98% of higher hydrocarbon destruction efficiency.

B. The flare must be designed and operated in a manner that will ensure no visible emissions during normal operation. Visible emissions means observations of smoke for any period or periods of duration greater than or equal to one (1)

minute in any fifteen (15) minute period during normal operation, pursuant to EPA Method 22. Visible emissions do not include radiant energy or water vapor.

C. The flare must be operated with a flame present at all times when emissions may be vented to it, or other mechanism that does not allow uncontrolled emissions.

D. All combustion devices must be equipped with an operating auto-igniter.

26. *Water Quality Monitoring Plan*. Oil and gas operations shall, to the extent practicable, avoid causing degradation to surface or ground waters within the City and to wetlands within the City. The following standards set forth by the City are consistent with the COGCC rules and regulations. If Operator needs to seek a variance from a COGCC provision then an approved COGCC variance will apply to this Agreement upon notice of such variance from Operator to the City.

Using records of the Colorado Division of Water Resources, Operator must implement a water quality monitoring and well testing plan that includes the following:

A. Operator must obtain initial baseline samples and subsequent monitoring samples from all available water sources within a one-half (1/2) mile radius of the Well Sites. Water sources include registered water wells or permitted or adjudicated springs.

B. Operator must collect initial testing of baseline samples from available water sources prior to the commencement of drilling a well, or prior to the re-stimulation of an existing well for which no samples were collected and tested during the previous 6-12 months.

C. Post-stimulation samples of available water sources shall be collected and tested pursuant to the following time frame:

1. One sample approximately one (1) year after commencement of the Production Phase;

2. One sample approximately three (3) years after commencement of the Production Phase; and

3. One sample approximately six (6) years after commencement of the Production Phase.

D. Operator shall collect a sample from at least one upgradient and two down-gradient water sources within a one-half (1/2) mile radius of a Well Site. If no such water sources are available, Operator shall collect samples from additional water sources within a radius of up to one (1) mile from the Well Site until samples from a total of at least one upgradient and two down-gradient water sources are collected. Operator should give priority to the selection of water sources closest to the Well Site.

E. Operator may rely on existing groundwater sampling data from any water source within the radii described above that was collected in accordance with accepted standards, provided the data was collected within the 12 months preceding the commencement of Drilling Phase for such Well Site, the data includes measurement of all of the constituents measured in Table 1 below and there has been no significant oil and gas activity within a one-mile radius in the time period between the original sampling and the commencement of the Drilling Phase for such Well Site.

F. Operator shall make reasonable efforts to obtain the consent of the owner of the water source. If the Operator is unable to locate and obtain permission of the water source, the Operator must advise the City that Operator could not obtain access to the water source from the surface owner.

G. Testing for the analytes listed in Table 1 below, and subsequent testing as necessary or appropriate.

H. Operator must follow standard industry procedures in collecting samples, consistent with the COGCC model Sampling and Analysis Plan.

I. Operator must report the location of the water source using a GPS with submeter resolution.

J. Operator must report results of field observations including reporting on damaged or unsanitary well conditions, adjacent potential pollution sources, odor, water color, sediment, bubbles, and effervescence.

K. Operator must provide copies of all test results described above to the City, the COGCC, and the water source owners within 30 days after receiving the samples.

L. Subsequent sampling. If sampling shows water contamination, additional measures may be required including:

1. If free gas or a dissolved methane concentration level greater than one (1) milligram per liter (mg/l) is detected in a water source, determination of the gas type using gas compositional analysis and stable isotope analysis of the methane (carbon and hydrogen).

2. If the test results indicate thermogenic or a mixture of thermogenic and biogenic gas, an action plan to determine the source of the gas.

3. Immediate notification to the City, the COGCC, and the owner of the water well if the methane concentration increases by more than five (5) mg/l between sampling periods, or increases to more than ten (10) mg/l.

4. Immediate notification to the City, the COGCC and the owner of the water well if BTEX and/or TPH are detected as a result of testing. Such detections may result in required subsequent sampling for additional analytes.

5. Further water well sampling in response to complaints from water source owners.

6. Timely production and distribution of test results in electronic deliverable format to the City, the COGCC and the water source owners.

7. Qualified Independent Professional Consultant. All water source testing must be conducted by the Operator or, if requested by a surface owner, by a qualified independent professional consultant.

Additionally, the City may make available a water testing program to any persons with an available water sources within one-half (1/2) mile of the radius of the proposed track of the borehole of any proposed New Well. If such sampling shows water contamination, the Operator shall work with the City and the COGCC to help identify the source of the contamination.

TABLE 1

GENERAL WATER QUALITY

Alkalinity, Conductivity & TDS, pH, Dissolved Organic Carbon (or Total Organic Carbon), Bacteria, and Hydrogen Sulphide

MAJOR IONS

Bromide, Chloride, Fluoride, Magnesium, Potassium, Sodium, Sulfate, and Nitrate + Nitrite as N

METALS

Arsenic, Barium, Boron, Chromium, Copper, Iron, Lead, Manganese, Selenium, Strontium, Mercury, Uranium, and Radium

DISSOLVED GASES and VOLATILE ORGANIC COMPOUNDS

Methane, Ethane, Propane, BTEX as Benzene, Toluene, Ethylbenzene and Xylenes, Total Petroleum, and Hydrocarbons (TPH)

OTHER

Water Level, Stable isotopes of water (Oxygen, Hydrogen, Carbon), Phosphorus.

27. *Landscaping.* Operator shall implement the Visual Mitigation Plan for a Well Site approved during the application process for such Well Site..

28. *Lighting.* The intent of this provision is to minimize light spillage beyond the perimeter of the Well Sites and for the Operator to take appropriate steps in order to achieve this. All permanent lighting or lighting higher than a perimeter wall must be downward facing. All bulbs must be fully shielded to prevent light emissions above a horizontal plane drawn from the bottom of the fixture. Prior to installation of permanent lighting on any facility, the Operator agrees to submit to the City a lighting plan and the City shall communicate with Operator any modifications to the plan that it deems appropriate and Operator shall make such modifications if reasonable or required by law. The lighting plan shall indicate the location of all outdoor lighting on the site and any structures, and include cut sheets (manufacturer's specifications with picture or diagram) of all proposed fixtures. During the Drilling and Completion Phases, consistent with applicable law, Operator will construct a minimum 32 foot wall around as much of the perimeter of the well pads as operations allow to reduce light escaping from the site, unless shorter walls are mutually agreed to by City and Operator on a site-specific basis.

29. *Maintenance of Machinery.* Routine field maintenance of vehicles or mobile machinery shall not be performed within three hundred (300) feet of any water body. All fueling must occur over impervious material.

30. *Mud Tracking.* The Operator shall take all practicable measures to ensure that vehicles do not track mud or debris onto City streets. If mud or debris is nonetheless deposited on City streets, in excess of *de minimus* levels, the streets shall be cleaned immediately by the Operator. If for some reason this cannot be done, or needs to be postponed, the City shall be notified of the Operator's plan for mud removal.

31. *Noise Mitigation.* Noise mitigation measures shall be constructed along any edge of any Well Site if such edge is in proximity to existing residential development. The noise mitigation measures shall use the most current equipment to minimize noise impact during the Drilling and Completion Phases, including those measures set forth in Sections 2 and 18. Operator shall comply with the sound limitation regulations set forth in COGCC 800 Series Aesthetic and Noise Control Regulations. The Operator shall not unload pipe between 8:00 p.m. and 7:00 a.m. The Operator will complete a baseline

noise mitigation study at each Well Site that demonstrates that noise is expected to be mitigated to the extent practicable and a copy will be provided to the City. A noise mitigation study has been completed that demonstrated that noise is expected to be mitigated to the extent practicable and to levels acceptable to the City. The Operator shall address C scale noise/vibration through berming and other associated BMPs. During the Drilling and Completion Phases, the operator shall construct a perimeter wall and/or use hay bales to mitigate noise as appropriate on a case-by-case or modeled basis. If Operator uses any engines that are not electrically operated, Operator shall use quiet design mufflers (also referred to as hospital grade or dual dissipative) or equivalent and shall use acoustically insulated housing or covers to enclose the engines.

The Operator shall comply with all provisions of COGCC Rule 802 on Noise Abatement with respect to the Well Sites; provided, however, that the Operator and City agree that the maximum permissible noise levels to be applied under Rule 802 shall be, other than during pad construction at the Well Sites, the greater of (i) the levels set forth for the land use type of "Residential/Agricultural/Rural" under Rule 802 if measurements are taken at 1,000 feet from the sound walls at the Well Site and (ii) 4 dB(A) higher than baseline ambient sound measured at 1,000 feet from the sound walls at the Well Site. During pad construction at the Well Sites, the Operator agrees that noise levels shall not exceed those produced by the construction of a typical residential or commercial development. All measurements considered for compliance with this Section 31 shall be taken by a third party contractor using industry standard equipment and practices.

Both the City and the Operator have conducted an Ambient noise survey for each Well Site at baseline and will place noise meters near Well Sites to monitor ongoing noise levels until the commencement of the Production Phase.

32. *Flowlines.* Any newly constructed or substantially modified flowlines on the Well Sites shall be constructed and operated under the provisions of the COGCC 1100 Series Flow line regulations, any future COGCC flowline regulations, and any applicable surface use agreements with the surface owners. Operator shall pressure test all flowlines following their construction, including those rated at less than 15 PSI. Operator will provide to the City all records required to be submitted to State agencies related to inspections, pressure testing, accidents and other safety incidents related to flowlines at the Well Sites and, upon specific request by the City, Operator will provide to the City any other records submitted to State agencies related to flowlines at the Well Sites.

33. *Recordation of Flowlines.* All new flowlines and pipelines shall have the legal description of the location recorded with the Clerk and Recorder of the City within thirty (30) days of completion of construction. Abandonment of any recorded flowlines shall be recorded with the Clerk and Recorder of the City within thirty (30) days after abandonment.

34. *Removal of Debris.* All construction-related debris shall be removed from the site for proper disposal in a timely manner. The site shall be maintained free of debris and excess

materials at all times during operation. Operator shall not burn or bury debris at any time on the Well Sites.

35. *Removal of Equipment.* All equipment used for drilling, re-completion and maintenance of the facility shall be removed from the site within thirty (30) days of completion of the work, weather condition permitting, unless otherwise agreed to by the surface owner. Permanent storage of removable equipment on Well Sites shall not be allowed.

36. *Plugged and Decommissioned Well Testing.* Prior to and following the fracturing of any New Well, Operator shall assess the integrity of plugged and decommissioned wells or removed from use and dry, or removed from use ("Previously Abandoned Wells), within one-quarter (¼) mile of the projected track of the borehole of the proposed New Well.

This shall include:

1. Based upon examination of COGCC and other publicly available records, identification of all Previously Abandoned Wells located within one-quarter (¼) mile of the projected track of the borehole of a proposed well.
2. Risk assessment of leaking gas or water to the ground surface or into subsurface water resources, taking into account plugging and cementing procedures described in any recompletion or plugged and abandoned report filed with the COGCC.
3. Notification of the City and COGCC of the results of the assessment of the plugging and cementing procedures.
4. Permission from each surface owner with a Previously Abandoned Well on their property to access the property to test the soil within a 10' radius of the Previously Abandoned Well. If a surface owner has not provided permission to access and test after thirty (30) days from receiving notice, the Operator shall not be required to test the Previously Abandoned Well. Notice to the surface owner will be sent by Certified US Mail, return receipt requested, to assure that the surface owner receives proper notice.
5. For each Previously Abandoned Well for which access and permission to test is granted, a soil gas survey to test the soil within a 10' radius of the Previously Abandoned Well shall be completed prior to production from the proposed New Well and again one (1) year after production has commenced on the New Well.
6. Notification of the results of the soil gas survey to the City and the COGCC within three (3) months of conducting the survey or advise the City that access to the Previously Abandoned Wells could not be obtained from the surface owner.

37. *Stormwater Control Plan.* All oil and gas operations at the Well Sites shall comply and conform with the City's stormwater control regulations, including the submission of an Erosion Control Report and Plan.

38. *Temporary Access Roads.* Temporary access roads associated with oil and gas operations at the Well Sites shall be reclaimed and revegetated to the original state within

a reasonable amount of time, taking into account planting seasons, or as directed by the landowner in a Surface Use Agreement and subject to applicable COGCC variances. Operator must control erosion while access roads are in use.

39. *Trailers.* A construction trailer(s) is permitted as an accessory use during active drilling and well completion or workover operations only. No permanent residential trailers shall be permitted at the Well Sites; provided, however, that until ninety (90) days following the end of the Completion Phase on a Well Site, temporary residential and/or security trailers are permitted, as needed for on-site operations, for exclusive use by the Operator's personnel and the personnel of its subcontractors on a temporary basis.

40. *Transportation and Circulation.* The Operator will comply with all Transportation and Circulation requirements as contained in the City Land Use Code as may be reasonably required by the City's Traffic Engineer and will comply with all applicable hazardous material regulations. The Operator will submit a traffic plan to the City that includes detailed descriptions of all proposed access routes for equipment, water, sand, waste fluids, waste solids, mixed waste, and all other material to be hauled on the public streets and roads of the City. The Operator will obtain necessary access permits. The traffic plan shall include the following:

A. estimated weights of vehicles when loaded, a description of the vehicles, including the number of wheels and axles of such vehicles and trips per day.

B. Detail of access locations for each well site including sight distance, turning radius of vehicles and a template indicating this is feasible, sight distance, turning volumes in and out of each site for an average day and what to expect during the peak hour.

C. Truck traffic volumes converted to equivalent single axle loads and compared with existing volumes. Trucks anticipated on roadways that are being accessed to equivalent single axle loads using existing volumes and proposed with extraction activities.

D. Core drilled samples of City roads to be used and determined the adequacy of the existing roadway structure and determined that the roadway section is adequate for extraction activities.

E. Truck routing map and truck turning radius templates with a listing of required and determined that certain improvements are necessary at intersections along the route.

F. Complete traffic report, determining operational changes and geometric modifications necessary as a result of extraction activities.

G. Identification of need for any additional traffic lanes, which would be subject to the final approval of the City's engineer.

H. Restriction of non-essential traffic to and from Well Sites to periods outside of peak am and pm traffic periods and during school hours (generally 7-9am and 3-6pm).

41. *Wastewater and Waste Management.* Operator must submit a waste management plan to the City that complies with the following: All fluids shall be contained and there shall be no discharge of fluids. Waste shall be stored in tanks, transported by tanker trucks and/or pipelines, and disposed of at licensed disposal or recycling sites. The plan shall incorporate secondary containment and stormwater measures consistent with Sections 8 and 37. No land treatment of oil impacted or contaminated drill cuttings are permitted. A copy of the Operator's Spill Prevention, Control, and Countermeasure Plan (SPCC) will be given to the City, which describes spill prevention and mitigation practices. The Operator shall not dispose of any wastewater within the City. All other waste shall be disposed of in accordance with state regulations.

42. *Water Supply.* The Operator agrees to comply with applicable State of Colorado, Department of Natural Resources and other applicable State regulations concerning the source(s) of water used in the Drilling Phase and Completions Phase. The Operator shall notify the City, upon its request, of the source(s) of water to be used at Well Sites during the Drilling Phase and Completion Phase and will provide the City with an estimate of the volumes of water to be utilized, with such estimates subject to change. All water volumes actually used by Operator shall be reported by the Operator to the State of Colorado in accordance with its regulations.

43. *Noxious Weed Control.* The Operator shall be responsible for ongoing noxious weed (as defined under State law) control at the Well Sites and along access roads per City or other applicable agency regulations.

44. *Insurance.* The Operator agrees to provide liability and insurance under the conditions, and in the amounts, set forth in Exhibit G.

45. *Injection Wells.* The Operator shall drill no injection wells in Broomfield.

46. *Alternative Site Analysis.* Operator has consulted with the City, to the City's satisfaction, in order to identify alternative sites based upon factors determined by the City. The Well Sites were mutually selected by the Operator and the City as the final sites following this consultation.

47. *General Maintenance.* Operator shall operate and maintain all equipment pursuant to manufacturer specifications consistent with technological limitations and reasonable and customary maintenance practices.

48. *Odor.* Odor emitting from Well Sites must be controlled. Operator to prevent odors from oil and gas operations by proactively addressing and, to the extent possible, resolving complaints filed by impacted members of the community, in coordination with City

public health staff. Operator must use a filtration system or additives to the drilling and fracturing fluids to minimize odors. Operator is prohibited from masking odors from any oil and gas facility site by using masking fragrances.

49. *Reclamation.* Operator must submit an oil and gas site reclamation plan and reclaim a Well Site not later than six (6) months after plugging and abandoning the last New Well at such Well Site, weather and planting season permitting.

50. *Well Integrity.* Operator must equip the bradenhead access to the annulus between the production and the surface casing, as well as any intermediate casing, with a fitting to allow safe and convenient determinations of pressure and fluid flow. Valves used for annular pressure monitoring shall remain exposed and not buried to allow for visual inspection. The Operator shall take bradenhead pressure readings as required by the COGCC.

51. *Fires and Explosions.* Any accident or natural event involving a fire, explosion or detonation shall be reported to the City within 24 hours. This report shall include such specifics, to the extent available:

A. Fuel source

B. Location

C. Proximity to residences and other occupied buildings

D. Cause

E. Duration

F. Intensity

G. Volume

H. Specifics and degree of damage to properties, if any beyond the Well Site

I. Injuries to person(s)

J. Emergency management response; and

K. Remedial and preventive measures to be taken within a specified amount of time

The Operator shall provide the City with an additional report containing the information above after the conclusion of the accident or natural event if lasting more than 24 hours.

52. *Spills.* Operator must notify the City of any spill of any material on permeable ground on the Well Sites that has a reportable spill quantity under any law. The Operator will also provide the City with a copy of any self-reporting submissions that Operator provides to the COGCC due to any spills at the Well Sites.

53. *Bradenhead Monitoring.* Operator will conduct bradenhead monitoring on the New Wells in accordance with COGCC Rules.

54. *Variances.* Except as specifically provided elsewhere in the Agreement, including its Exhibits, all variances, waivers, exceptions, and similar modifications require written

approval from the City, such approval not to be unreasonably withheld, conditioned or delayed.

55. *Risk Assessment.* As part of Operator's application to the City, Operator agrees to provide a risk management plan, which will include the identification of potential risks, methods of risk avoidance and controls that implement techniques to prevent accidents and losses and reduce the impact or cost after the occurrence of identified potential events.

56. *Automatic Safety Protective Systems and Surface Safety Valve.* An automated safety system, governed by safety devices and a programmable logic computer, will be installed at the Well Sites. The automated safety system shall include the installation, monitoring and remote control of a Surface Safety Valve ("SSV") among many other engineered measures and devices that are implemented to greatly reduce or eliminate the potential for a well event. All New Wells will have a SSV installed prior to the commencement of the Production Phase connected to the production tubing at the surface. The SSV will be equipped to operate remotely via the automated safety protective system, which monitors multiple flowing pressures and rates which have predetermined maximum and/or minimum threshold values programmed and will remotely shut the well in should certain upset conditions be detected. Additionally, the automated safety system provides the ability to remotely shut-in wells on demand through operator remote intervention. The SSV will have documented quarterly testing to ensure functionality. The practice of utilizing automated safety protective systems, including SSV's, exceeds the current State regulations and requirements for wells operated within Colorado.

57. *Possible Berms, Bales or Sound Walls.* Operator shall utilize the additional mitigation measures of berms, bales, and/or sound walls at one or more of the locations set forth on Exhibit I if so requested by the City in writing. The particular measure(s) employed at any such location shall be as determined by mutual agreement between the City and the Operator.

Exhibit C

List of P&A Wells

Well Name	API	QQ	Section	Township	Range
Beyer MA #10-5	05-014-09171	SWNW	10	1S	68W
BROZOVICH #MA 8-2	05-014-09142	NW/NE	8	1N	68W
BROZOVICH #MA 8-8J	05-014-08812	SE/NE	8	1S	68W
Brozovich MA 8-10	05-014-09150	NWSE	8	1S	68W
Brozovich MA 8-15	05-014-09151	SWSE	8	1S	68W
Brozovich MA 8-16J	05-014-08928	SESE	8	1S	68W
Carlson #1-24	05-014-06269	SWSE	24	1S	68W
FEDOROWICZ 1-17	05-014-09029	NESW	17	1S	68W
Fedorowicz 2-17	05-014-09075	NENW	17	1S	68W
Foster 1-22	05-001-09132	NWSW	22	1S	68W
GREEN MA 17-1	05-014-09168	NENE	17	1S	68W
GREEN MA 17-15	05-014-09174	SWSE	17	1S	68W
GREEN MA 17-16J	05-014-08996	SESE	17	1S	68W
GREEN MA 17-2	05-014-09166	NWNE	17	1S	68W
GREEN MA 17-8J	05-014-08999	SENE	17	1S	68W
GREEN MA 17-9	05-014-09172	NESE	17	1S	68W
Hellerstein 2-18	05-014-09065	SESE	18	1S	68W
HIPPEN 2-32	05-123-15113	NWSW	32	1N	68W
HULSTROM 'G' UNIT #1	05-014-09177	SE/NE	4	1S	68W
LARKRIDGE MA 03-09D	05-001-09715	NESE	3	1S	68W
LARKRIDGE MA 03-10D	05-001-09716	NESE	3	1S	68W
LARKRIDGE MA 03-15D	05-001-09717	NESE	3	1S	68W
LARKRIDGE MA 03-16D	05-001-09713	NESE	3	1S	68W
LARKRIDGE MA 03-23D	05-001-09714	NESE	3	1S	68W
Livingston 43-07	05-014-09435	NESE	7	1S	68W
Maloney #2-16	05-001-08809	NWNW	16	1S	68W
Maloney 1-16	05-001-08674	NWNE	16	1S	68W
NORDSTROM #2-4	05-014-08793	SW/SW	4	1S	68W
NORDSTROM #5-4	05-014-09032	NE/SW	4	1S	68W
Nordstrom 1-9	05-014-08671	SENE	9	1S	68W
Nordstrom 3-9	05-014-08929	SENW	9	1S	68W
NORTH HURON 1-22	05-001-09035	NWNW	22	1S	68W
PEZOLDT UU 32-4J	05-123-17184	NWSE	32	1N	68W
POITZ 1-22	05-001-08428	NENE	22	1S	68W
Sharpe 1-10	05-001-08512	SESE	10	1S	68W
Sharpe 2-10	05-014-08876	NESW	10	1S	68W
W.W.C. 1-9	05-001-08902	SWSE	9	1S	68W
WEBBER 'H' UNIT #1	05-014-09114	SE/SW	3	1S	68W
YOUNG 4-31	05-123-16183	NWNW	31	1N	68W

NOTE: The following wells have already been plugged and abandoned in 2017

Mathena 1-15	05-014-08666	NWNW	15	1S	68W
W.W.C. 2-9	05-001-09042	SESE	9	1S	68W
PEZOLDT 1-32	05-123-15040	NWNE	32	1N	68W

EXHIBIT D
PIPELINE SPECIFICATIONS

Design

1. Pipeline shall be constructed with a Class 4 Design (0.40 Design Factor) for steel pipelines.
2. For steel pipelines, utilize Fusion Bond Epoxy (FBE) Coated Pipe (or equivalent), which is intended to protect pipe from corrosion
3. Utilize a cathodic protection system
4. Hydrostatic test to 1.25 times the Maximum Operating Pressure for four (4) hours for exposed pipe and eight (8) hours for buried pipe
5. Utilize In-Out measurement for Leak Detection
6. Utilize automated systems for over pressure protection & low pressure detection that shuts-in the pipe in order for Operator to investigate

Construction

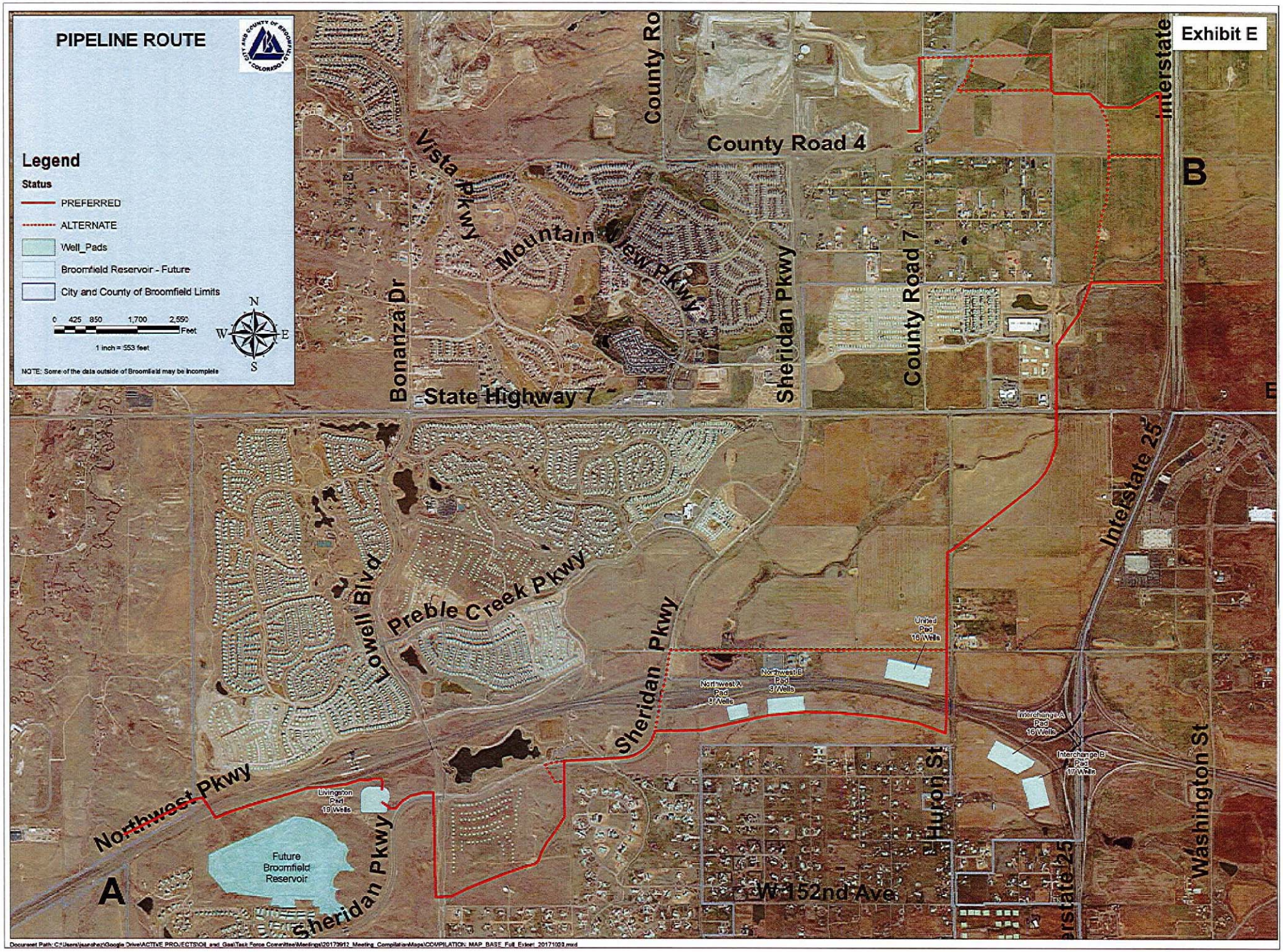
1. Conduct X-ray on 100% of welds.
2. For buried pipe, pipe shall be buried a minimum of 48" from the surface.
3. Conduct survey and logging for every girth weld in place.
4. Utilize jeeping (holiday detector) as well as visual inspection of coating. Once a jeep (damage) is detected, pipe coating shall be repaired and re-jeeped until damage is repaired and does not cause a jeep or detection.
5. Following construction, site shall be left in as good a condition as prior to construction and Operator shall work with the applicable surface owner on restoration. Operator shall restore the site to a substantially similar condition as it existed prior to construction unless otherwise agreed by the City in writing.
6. All steps and or phases of construction shall be inspected by Operator's 3rd party inspectors.
7. Roads, creeks and other encumbrances shall be bored underneath at a safe depth.

Operation & Maintenance

1. Operator to conduct regular pigging on the pipelines
2. Operator to conduct smart pigging every 5 years to detect anomalies such as internal and external corrosion or denting.
3. Operator to conduct leak detection, including aerial surveys at least 2 times per year.
4. With respect to each Well Site, Operator to conduct pre-drill and post-drill pressure testing, pressure testing before commencing every phase of operations, and annual pressure testing thereafter.
5. To the maximum extent feasible, all flow lines, gathering lines, and transmission lines shall be sited a minimum of one-hundred and fifty (150) feet away from general residential, commercial, and industrial buildings, as well as the high-water mark of any surface water body. This distance shall be measured from the nearest edge of the pipeline

or flowline. Pipelines and gathering lines that pass within 150 feet of general residential, commercial, and industrial buildings or the high water mark of any surface water body shall incorporate leak detection, secondary containment, or other mitigation, as appropriate. The mitigation plan for such pipelines and gathering lines shall be submitted to the City.

6. To the maximum extent feasible, Operator shall use boring technology when crossing streams, rivers, or irrigation ditches with a pipeline to minimize negative impacts to the channel, bank, and riparian areas
7. All new pipelines shall have the legal description of the location recorded with the Clerk and Recorder of the City within thirty (30) days of completion of construction.
8. Operator will submit to City all records required to be submitted to PHMSA or the PUC including those related to inspections, pressure testing, pipeline accidents and other safety incidents.



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EASEMENT GRANT

THIS EASEMENT GRANT ("*Grant*") is made this _____ day of _____, 2017 by The City and County of Broomfield, whose address is One DesCombes Drive, Broomfield, Colorado 80020, hereinafter called ***"Grantor"*** or ***"City"*** (whether grammatically singular or plural), to Extraction Oil & Gas Inc., a Delaware Corporation, whose address is 370 17th Street, Suite 5300, Denver, CO 80202, hereinafter called ***"Grantee"***. Grantor and Grantee are collectively called "***Parties***" and individually "***Party***." The Parties agree as follows:

WITNESSETH:

For and in consideration of Ten Dollars and 00/100ths ($10) and other good and valuable consideration, the receipt whereof is and sufficiency of which are hereby acknowledged, Grantor hereby grants, conveys and warrants to Grantee, its agents, successors and assigns, non-exclusive perpetual easements (each, an "Easement") for the purposes and uses described herein along certain rights-of-way and other property owned by the Grantor, situated in the City and County of Broomfield, State of Colorado, as described in the map attached hereto and incorporated herein by reference as Exhibit A (hereinafter referred to as the "Easement Areas"). A legal description of the mutually agreed as-built Easement Areas will be attached hereto as Exhibit B and, once attached, shall be incorporated into this Grant. The Parties acknowledge that any grant made for the use of an existing public right-of-way owned by the City shall be a shared use consistent with the requirements set forth in Chapter 14-10 of the Broomfield Municipal Code, the Amended and Restated Operator Agreement between the City and Operator, dated October 24, 2017 (the "Operator Agreement"), and other applicable federal, state, and local laws.

The conditions of this Grant are as follows:

1. This Easement, as granted by the Grantor to the Grantee, shall be for the purpose of entering, occupying and using laying, constructing, maintaining, operating, patrolling, repairing, replacing, accessing, surveying, placing, traveling across, using, installing, inspecting, relocating, rebuilding, changing in size, reconstructing, altering, marking, monitoring, improving, enlarging, abandoning, removing and reclaiming certain above and below ground pipelines (with fittings, tieovers, cathodic protection equipment, valves, manholes, gas meter/regulator stations, guardrails, fences, devices, launchers, receivers and valve stations and all appliances appurtenant thereto) for the transportation or transmission of oil, gas, petroleum products, water, electricity, hydrocarbons and other liquids or any other substances whether fluid, solid or gaseous, and any products, derivatives, combinations or mixtures of any of the foregoing and associated with crude oil along routes across the Easement Areas. All pipelines shall be below ground as set forth herein except for the water pipeline as shown on Exhibit A.

2. Grantee shall have and exercise all rights, privileges and benefits necessary or convenient for the full use and enjoyment of this Easement, including, but not limited to, the right of ingress and egress in, to, over, through and across the described Easement Areas and Grantor's lands lying adjacent to the Easement Areas, for any and all purposes needed for the full use and enjoyment of the right of occupancy or use provided for herein. Grantee shall lay all

below ground pipelines in the Easement Areas at a depth of not less than 48 inches below the surface of the ground, except for the pipelines traversing through Section 4 and Section 34, Township 1 South, Range 68 West, 6th P.M. along Huron Street between 160th Avenue and Highway 7, which will run not less than 92 inches deep below final grade. The width of the Easement Areas shall be one-hundred feet (100') during the initial construction and subsequent repairs, replacement, relocation, rebuilding, reconstruction, or removal of the Lines and, at all other times, the width of the permanent Easement shall be thirty feet (30').

3. Except as stated above, the Grantee shall not construct or place any permanent structure, building, improvement, or fixture on any portion of the above described of the Easement Areas. The Grantee may construct and permanently place pipeline markers and cathodic protection leads within the Easement Areas on an as needed basis to the extent such improvements are required by applicable regulations. Any other above-ground construction within the Easement Areas shall be subject to advance approval of Grantor, approval not to be unreasonably withheld.

4. After construction of the pipelines, as hereinabove referred to, Grantee shall repair and reclaim any damages it may cause to any public improvements located within or upon the Easement Areas, including but not limited to any damages to any public right- of-way, landscaping, sidewalks, streets, highways, trails, lighting, signage, signals, and utilities. Additionally, the Grantee shall repair and restore the general surface of the ground of the Easement Areas to the grade and condition it was in immediately prior to construction as near as practical, at the Grantee's sole cost and expense. Grantee shall repair and restore, at the Grantee's sole cost and expense, any publicly improved rights-of-way as required by the City's engineer. Grantee shall reclaim any disturbed surface area within the Easement Areas, including the removal of any excess earth resulting from installation by the Grantee, and shall reseed as needed utilizing native seed mix. All reclamation of the Easement Areas shall be at the sole expense of the Grantee. Grantee shall maintain the right to cut and keep the Easement Areas clear of all trees, brush and other obstructions that may injure, endanger or interfere with the construction and use of said pipelines.

a. Maintenance and General Operation. The Grantee shall at all times keep the Easement Areas, access roads used exclusively by them, and pipeline easements used exclusively by them safe and in good order and free of noxious weeds, litter and debris. The Grantee shall dispose of all litter, sewage, waste, and debris caused or created by Grantee off the Easement Areas at an appropriate disposal site. Grantee shall promptly reclaim and reseed the Easement Areas in accordance with the Operator Agreement and applicable federal, state, and local regulations and use reasonable efforts to prevent the release or discharge of any toxic or hazardous chemicals or wastes on the Property; provided, however, in the event of a release or discharge, Grantee shall comply with the terms of the Operator Agreement and applicable federal, state, and local regulations and any other applicable laws, rules, and regulations that apply to the release or discharge.

b. Water, Fluids and Waste. All water, fluids and waste of any nature whatsoever which are used, produced or discharged from the Grantees' operations or

facilities shall be used, produced and discharged in accordance with all applicable rules and regulations of the governmental authorities having jurisdiction over such matters. Further, all water, fluids and waste of any nature whatsoever which are used, produced or discharged in connection with the Grantees' oil and gas operations shall not be discharged on, in, under, or near the Easement Areas and shall be discharged and held only in a closed loop system. The Grantee shall implement industry standard management practices to avoid the spill, release or discharge of any pollutants, contaminants, chemicals, solid wastes, or industrial, toxic or hazardous substances or wastes at, on, in, under, or near the Easement Areas, including those set forth in the Operator Agreement. Any such spill, release or discharge, including without limitation, of oil, gas, grease, solvents, or hydrocarbons that occurs at, on, in, under, or near the Easement Areas shall promptly be remediated in compliance with applicable laws and the Operator Agreement. Any such spill, release or discharge that is reportable to regulatory authorities under applicable laws shall be reported to the owner of the Easement within 24 hours by telephone, fax, or e-mail, to be followed by copies of written notices that Grantee has filed with regulatory authorities within five business days after such filing.

5. The Grantee, by acceptance hereof, agrees to pay for damages to any existing or future public improvements to the Easement Areas which may arise from laying, constructing, maintaining, operations, repairing, replacing or removing said pipeline. Further, the Grantee agrees to pay for any relocations of the pipeline that are made at the request of the City, provided the City's request is made pursuant to Section 14-10-190 of the Broomfield Municipal Code. Any relocation requested by the City which is not subject to Section 14-10-190 shall be at the expense of the City.

6. The Grantee shall take reasonable measures to minimize erosion of the surface of the Easement Areas caused by its operations within the Easement Areas.

7. Grantor has retained the right to the use and occupancy of the Easement Areas insofar as such use and occupancy is consistent with and does not in any way interfere with or impair the grant herein contained and except as herein otherwise provided. Grantee acknowledges that Grantors current and planned uses of the Easement Areas include certain public improvements within the Easement Areas, including but not limited to, landscaping, public rights-of-way, public open space and open lands, sidewalks, streets, highways, trails, lighting, signage, signals, pipelines and utilities ("***Site Improvements***"). Any grant contained herein permitting the Grantee to use the public right-of-way for its operations shall be secondary to any public use of the right-of-way and shall be reconciled with any competing uses. Any use of public open space or open lands by the Grantee shall not unreasonably interfere with said public uses. Site Improvements may be installed in the Easement Area as long as such uses do not interfere with Grantee's rights as herein granted. Without limiting the generality of the foregoing, (1) there shall be no excavation or planting of deep rooted trees or shrubs by Grantor, or anyone acting on behalf of, or through Grantor, within fifteen feet (15') of the centerline of any installed pipeline; and (2) if Grantor desires to construct a fence, the fencing must be designed, installed and maintained by Grantor so that at all times the Easement Areas are passable by Grantee, its contractors, agents, and invitees, through a gate no less than fifteen feet

(15') wide and Grantee must be provided a key, access code, or other means of releasing any lock or security device on such gate. Grantee shall be allowed, upon notice to the City, to cut, prune, or otherwise control, shrubs, trees, and other vegetation which may adversely impact the Grantee's use of the Easement Areas. In the event any shrubs, trees, or other vegetation needs to be permanently removed so as not to adversely impact the Grantees use of the Easement Areas, the Grantee shall work with the City to identify a mutually agreeable solution. Any such maintenance activities initiated by the Grantee shall be at the Grantee's sole cost and expense. If Grantor builds, constructs, or permits to be built or constructed any obstruction, building, fence, landscaping, reservoir, engineering works or other structures or Site Improvements over, under or across the Easement Areas that interferes with Grantee's use of the Easement Areas, Grantor and Grantee will work to identify a mutually agreeable solution.

8. The Grantor warrants that he has full right and lawful authority to make the grant hereinabove contained, and promises and agrees to defend the Grantee in the exercise of its rights hereunder against any defect in his title to the land involved or his right to make the grant hereinabove contained.

9. Each and every one of the benefits and burdens hereunder shall inure to and be binding upon the respective legal representatives, heirs, successors, executors, administrators, and assigns of the parties hereto.

10. All costs associated with the Grantee's use of the Easement Areas and the Grantee's responsibilities pursuant to this Agreement, including, but not limited to, costs associated with laying, constructing, maintaining, operating, patrolling, repairing, replacing and removing any of its pipelines or other improvements to the Easement Areas shall be borne by Grantee; and Grantee shall and does hereby agree to indemnify and hold Grantor harmless from all claims for damages or liens arising from the operation, use, laying, constructing, maintaining, operating, patrolling, repairing, replacing and removing of any of its pipelines or other improvements to the Easement Areas. Grantee assumes liability for injury to person and damage to the Easement Areas and other areas of the Grantor's property arising out of the Grantee's actions or omissions in using, occupying, and maintaining the Easement Areas. Nothing contained herein shall constitute any waiver by Grantor of the provisions of the Colorado Governmental Immunity Act or any other immunity or defense provided by statute or common law.

11. The Grantor reserves the right to cross pipeline and flowline easements at approximately right angles, and the Grantor shall also have the right to install and maintain easements that are adjacent to or within the Company's pipeline and flowline easements as depicted on Exhibit B for utility lines, including those for water, gas, sewer, electric, telephone, cable, television, fiber optics, other pipelines, and other utilities; provided, however: i) any new underground facilities which travel along a pipeline easement or flowline easement identified herein shall be located a distance horizontally of at least ten (10') feet from parallel existing pipelines and flowlines; ii) any new underground facilities shall have at least twenty-four (24) inches of vertical clearance between the new facility and a flowline or pipeline provided for herein; and iii) any overhead power lines shall be at least twenty (20') feet above the ground. In

certain areas depicted in Exhibit A the underground pipelines with run within the City right-of-way which will be a shared use of the City right-of-way with other public and private utility providers. Uses within the City right-of-way shall be in conformance with Chapter 14-10 of the Broomfield Municipal Code and all other local, state, and federal rules, regulations, and laws..

12. The Grantee hereby agrees to conduct its operations in accordance with the Operator Agreement and in a manner which prevents any contamination by oil, gas or other hydrocarbon substances or related exploration for, or development and production of oil, gas or other hydrocarbon substances at, on, under or near the Easement Areas. If contamination has been caused by the Grantee's operations, the Grantee shall immediately remediate and indemnify and hold the City harmless for such contamination at their sole expense. Any obligation of the Grantee to remediate and indemnify the Grantor shall include, but not be limited by, the following environmental obligations:

a. Environmental Indemnity. The environmental matters shall be governed exclusively by the following:

(i) "Environmental Claims" shall mean all Claims asserted by the Grantor, governmental bodies or other third parties for pollution or environmental damage of any kind, arising from operations on or ownership of the Easement Areas, and all cleanup and remediation costs, fines and penalties associated therewith, including any Claims arising from Environmental Laws or relating to asbestos or to naturally occurring radioactive material. Environmental Claims shall not include the costs of any remediation undertaken voluntarily by any party, unless such remediation is performed under the imminent threat of a Claim by a governmental body or other third party.

(ii) "Environmental Laws" shall mean any laws, regulations, rules, ordinances, or order of any governmental authority(ies), which relate to or otherwise impose liability, obligation, or standards with respect to pollution or the protection of the environment, including without limitation, the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (42 U.S.C. § 9601 *et seq.*), the Resource Conservation and Recovery Act of 1976 (42 U.S.C. §§ 6901 *et seq.*), the Clean Water Act (33 U.S.C. §§ 466 *et seq.*), the Safe Drinking Water Act (14 U.S.C. §§ 1401-1450), the Hazardous Material Transportation Act (49 U.S.C. §§ 1801 *et seq.*), the Clean Air Act, and the Toxic Substances Control Act (15 U.S.C. §§ 2601 - 2629).

(iii) Indemnification. The Grantee shall protect, defend, indemnify, and hold harmless Grantor from any Environmental Claims relating to the Easement Areas or the associated oil and gas operations areas that arise out of the operations of the Grantee and their agents, employees, contractors and representatives of any Grantee pipeline or Grantee flowline easement on the

Easement Areas. This indemnity specifically covers, but is not limited to, the Grantee's use of the Easement Areas.

b. Exclusion From Indemnities. The indemnities of the Parties herein shall not cover or include any amounts which the indemnified party is actually reimbursed by any third party, net of reasonable attorney's fees and costs incurred by the indemnified party in recovering such amounts. The indemnities in this Agreement shall not relieve any party from any obligations to third parties.

c. Release. To the maximum extent permitted by applicable laws, the Grantee hereby release and waive and discharge the Grantor, its insurers, elected officials, respective managers, officers, directors, employees, agents, attorneys, successors, and assigns, from any and all liability for personal injury, death, property or other damage, or otherwise arising out of the Grantees' or their agents', employees', contractors' and representatives' operations under this Agreement or their use of the Easement Areas, unless such injury, death, or damage is the result of the City's negligence, gross negligence or willful misconduct.

13. The above and foregoing constitute all terms and conditions of this grant and no additional or different oral representation; promise or agreement shall be binding on Grantor or the Grantee with respect to the subject matter of this Grant. The Parties agree that this agreement remains subject to the Operator Agreement. To the extent that any provisions hereof conflict with any provisions of the Operator Agreement, such provisions of the Operator Agreement shall control and supersede any other term or provision hereof. This Grant is freely assignable without restriction.

14. The Grantee shall comply with all common law, statutory and regulatory laws, permit requirements and conditions, all regulations of the Colorado Oil and Gas Conservation Commission, and the standards contained in the oil and gas section of Broomfield's Comprehensive Plan, as such laws apply to its operations and use of the Easement Areas, including, but not limited to plugging and abandoning of oil and gas operations areas and pipelines in the Easement Areas in accordance with all applicable law. At the time the Easement Areas ceases to be used or useful by Grantee, it shall abandon and remove the pipeline in accordance with the Operator Agreement and all applicable law and this grant of easement shall terminate, with all indemnification provisions contained in this Easement Grant surviving such termination.

15. **Notices.** Any notice required or permitted under this Grant shall be in writing and shall be sufficient if personally delivered or mailed by certified mail, return receipt requested, addressed to the following:

If to the Grantor:

City and County Manager
City and County of Broomfield
One Descombes Drive
Broomfield, Colorado 80020

If to Grantee:

Extraction Oil & Gas, Inc.
Attn: Legal Department
370 17th Street, Suite 5300
Denver, Colorado 80202

Notices mailed in accordance with the provisions of this Paragraph shall be deemed to have been given upon mailing. Notices personally delivered shall have been deemed to have been given upon delivery. Either party may change its address by giving notice thereof to the other party in the manner provided in this Paragraph.

16. Grantee shall record an original of this Grant and any amendments thereto in the records of the City.

17. The failure of either party to exercise any of its rights under this Grant shall not be a waiver of those rights. A party waives only those rights specified in writing and signed by the party waiving its rights.

(Signature Page to Follow)

IN WITNESS WHEREOF, the parties hereto have entered into this as of the day and year first set forth above.

EXTRACTION OIL & GAS, INC.

_____

Matthew R. Owens, President

STATE OF COLORADO)

)ss

COUNTY OF _____)

The foregoing easement was acknowledged before me this _____ day of _____ 2017, by _____.

Witness my hand and official seal.

(SEAL)

_____

Notary Public

My commission expires _____

CITY AND COUNTY OF BROOMFIELD

_____
Mayor

ATTEST:

_____
CITY AND COUNTY CLERK

APPROVED AS TO FORM:

CITY AND COUNTY ATTORNEY

EXHIBIT A

Pipeline Route

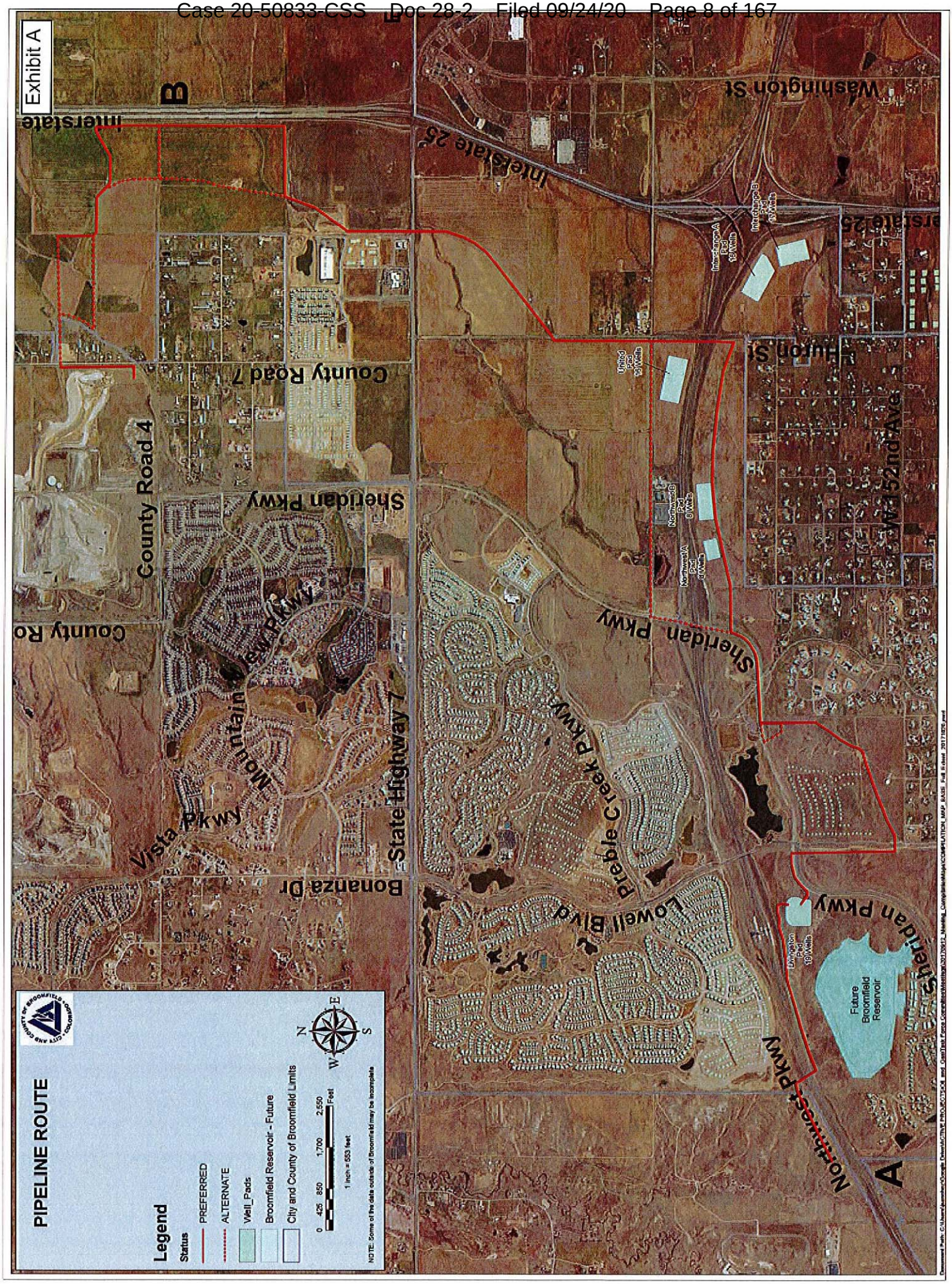

Exhibit A
PIPELINE ROUTE
Legend
Status
PREFERRED
ALTERNATE
Well_Pads
Broomfield Reservoir - Future
City and County of Broomfield Limits
0 425 850 1,700 2,550 Feet
1 inch = 553 feet
NOTE: Some of the data outside of Broomfield may be incomplete
A
B
E
Interstate
Interstate 25
Washington St
Huron St
W 152nd Ave
County Road 7
County Road 4
County Ro
Sheridan Pkwy
Mountain View Pkwy
Vista Pkwy
Bonanza Dr
State Highway 7
Lowell Blvd
Pebble Creek Pkwy
Northmoor Pkwy
Future Broomfield Reservoir
Interchange A Pad 18 Wells
Interchange B Pad 9 Wells
United Pad 10 Wells
Northwest B Pad 8 Wells
Northwest A Pad 8 Wells
Lehigh Pad 19 Wells

Exhibit B

As-Built Legal Description of the Easement Areas

EXHIBIT G
Insurance Requirements

During the term of the Agreement, Operator shall comply with the following requirements:

1. Operator shall maintain or cause to be maintained, with insurers authorized by the state of Colorado and carrying a financial strength rating from A.M. Best of no less than A- VII (or a similar rating from an equivalent recognized ratings agency), at a minimum, the following types of insurance with limits no less than the amounts indicated:

A. Commercial General Liability insurance on an occurrence based form including coverage for bodily injury or property damage for operations and products and completed operations with limits of not less than $1,000,000 each and every occurrence.

B. Automobile Liability insurance with limits of not less than $1,000,000 each and every occurrence.

C. Workers' Compensation insurance - Statutory Workers' Compensation Coverage for the employee's normal State of employment/hire. Including Employer's Liability insurance – with limits of not less than $1,000,000 Each Accident, Disease–Each Employee, Disease–Policy Limit.

D. Control of Well/Operators Extra Expense insurance – with limits of not less than $10,000,000 covering the cost of controlling a well that is out of control or experiences a blowout, re-drilling or restoration expenses, seepage and pollution damage resulting from an out of control well or blowout as first party recovery for the operator and related expenses, including, but not limited to, loss of equipment and evacuation of residents.

E. Umbrella/Excess Liability – in excess of General Liability, Employer's Liability, and Automobile Liability with limits no less than $25,000,000 per occurrence; provided, however, that for so long as the Construction Phase, Drilling Phase or Completions Phase is ongoing at any of the Well Sites, Operator will maintain such insurance with limits no less than $100,000,000 per occurrence.

F. Environmental Liability/Pollution Legal Liability insurance – with limits of not less than $5,000,000 per pollution incident, with coverage being required beginning with the date that is eight (8) years from the date of first production from the first New Well (the "Required Date"). Coverage must include gradual pollution events. This insurance may be on a claims-made basis, however the retroactive date must precede the Required Date in order to cover all New Wells and Well Sites.

2. Operator shall waive and cause its insurers under the above policies to waive for the benefit of the City any right of recovery or subrogation which the insurer may have or acquire against BROOMFIELD or any of its affiliates, or its or their employees, officers or directors for payments made or to be made under such policies.

3. As it pertains to the risks and liabilities assumed by Operator under this Agreement, Operator agrees to add the City and its elected and appointed officials and employees as Additional Insureds under general liability (including operations and completed operations), auto liability and umbrella liability.

4. Operator shall ensure that each of the policies are endorsed to provide that they are primary without right of contribution from the City or any insurance or self-insurance otherwise maintained by the City, and not in excess of any insurance issued to the City.

5. Operator shall ensure that each of the policies above (excluding workers' compensation and OCC/COW) are endorsed to state that the inclusion of more than one insured under such insurance policy shall not operate to impair the rights of one insured against another insured and that the coverage afforded by each insurance policy shall apply as though a separate policy had been issued to each insured.

6. All policies shall be endorsed such that they cannot be canceled or non-renewed without at least 30 days' advanced written notice to the Operator and the City, evidenced by return receipt via United States mail, except when such policy is being canceled for nonpayment of premium, in which case 10 days advance written notice is required. Language relating to cancellation requirements stating that the insurer's notice obligations are limited to "endeavor to" are not acceptable.

7. Operator shall, prior to permit issuance, deliver Certificates of Insurance reasonably acceptable to the City confirming all required minimum insurance is in full force and effect.

8. Deductibles or retentions shall be the responsibility of Operator. Deductibles or retentions must be listed on the Certificate of Insurance required herein and are subject to the reasonable approval of the City.

9. Operator shall require any of its subcontractors to carry the types of coverage and in the minimum amounts in accordance with the requirements set out in Section 1.A, 1.B and 1.C. Operator agrees that it shall be responsible for any damage or loss suffered by the City as a result of non-compliance by Operator or any subcontractor with this section.

10. In the event that Operator's coverage lapses, is cancelled or otherwise not in force, the City reserves the right to obtain insurance required herein and charge all costs and associated expenses to Operator, which shall become due and payable immediately.

11. In the event that the coverage required by Section 1.F is not widely available to operators in the Denver-Julesburg Basin, in lieu of the coverage required by Section 1.F, Operator and the City shall establish a joint escrow account that shall be used to satisfy any obligations of Operator that would have otherwise have been covered by the coverage required by Section 1.F. Operator shall fund such account with an amount equal to $5,000.00 per New Well then-producing (the "Per Well Amount"). The aggregate amount to be placed into the account shall be re-visited on an annual basis based on the then-number of producing New Wells. The Per Well Amount shall be adjusted each year by the increase or decrease in the Consumer Price Index issued by the United States Bureau of Labor Statistics for the Denver – Boulder metropolitan area. Any interest accrued in the account shall be credited towards the Operator's required contributions to the account and any excess amounts in the account above and beyond the amount required by this provision shall be promptly returned and released to Operator.

Exhibit H

SURFACE USE AGREEMENT

This Surface Use Agreement (hereinafter "**Agreement**"), is made and entered into effective this 24th day of October, 2017 (the "**Effective Date**"), by and between Extraction Oil & Gas, Inc. ("**Operator**" or "**Extraction**"), a Delaware corporation located at 370 17th Street, Suite 5300, Denver, CO 80202 and the City and County of Broomfield, Colorado, a municipal corporation, with an address of One DesCombes Drive, Broomfield, Colorado 80020 ("**Surface Owner**" or "**City**"). Operator and Surface Owner may each be referred to herein individually as a "**Party**" and collectively as the "**Parties**."

RECITALS

WHEREAS, City owns the surface and the minerals of certain lands located in City and County of Broomfield, which are more particularly described as:

TOWNSHIP 1 SOUTH, RANGE 68 WEST, 6th P.M.
Section 9: Part of the N½ of Section 9, the City and County of Broomfield, State of Colorado and also designated as City and County of Broomfield Open Space ("**Open Space**"); and

TOWNSHIP 1 SOUTH, RANGE 68 WEST, 6th P.M.
Section 7: Part of the NE¼ of the SE¼ of Section 7, the City and County of Broomfield, State of Colorado and also designated as City and County of Broomfield Open Lands ("**Open Lands**") on which the Livingston 43-7 well is currently owned and operated by Operator

Both as more particularly depicted on the map attached hereto as **Exhibit A** (the "**Surface Lands**" or "**Lands**");

WHEREAS, Operator owns interests in oil and gas leases covering lands adjacent to and including the Surface Lands (the "**Leases**");

WHEREAS, Operator intends to explore, develop, drill, construct, complete, produce, maintain, rework, operate, plug and abandon, and reclaim horizontal oil and gas wells ("**Northwest and United Wells**" and "**Livingston Wells**" or "**New Wells**") from the Surface Lands for purposes of producing oil, gas and other minerals from the Leases and other nearby lands. New Wells shall be located on the oil and gas Well Sites described on **Exhibit B** attached hereto known as production pads for the Northwest A & B and United B Well Site (the "**Northwest & United Well Sites**") and the Livingston Well Site (the "**Livingston Wells**", and collectively with the Northwest & United Well Sites, the "**Well Sites**");

WHEREAS, it is necessary that Operator enter, occupy and use a portion of the Surface Lands to explore, survey, develop, drill, construct, complete, produce, maintain, rework, operate, plug and abandon, and reclaim the Surface Lands of the New Wells, and all Facilities associated therewith including for Oil and Gas Operations. "**Oil and Gas Operations**" has the meaning set

forth for such term in the 100 Series of the Rules and Regulations of the Colorado Oil and Gas Conservation Commission ("**COGCC**");

WHEREAS, Operator also desires to access and use on a non-exclusive basis the surface and subsurface of certain portions of the Lands in connection with Operator's Oil and Gas Operations for the construction, use, and maintenance of access roads (including existing roads on the Lands) (**"Access Roads"**), oil, gas and water pipelines (the "**Pipelines**"), and the installation and location of electrical power lines and other specialized equipment necessary to support its Oil and Gas Operations, including but not limited to constructing production facilities, emission control devices, vapor recovery towers, vapor recovery units, flowlines, gathering lines, gas gathering systems, temporary above ground water lines, temporary above ground completion fluid lines or fresh water lines, separators, pig launchers, compressor sites, and receivers (each a "**Facility**" or collectively **"Facilities"**);

WHEREAS, the location of necessary Access Roads, Pipelines, and Facilities are more particularly depicted on the map attached hereto as **Exhibit C**;

WHEREAS, it is expected that Operator will need to use approximately thirty-two and one-half (32.5) acres of the City's Lands for its Oil and Gas Operations and related Facilities;

WHEREAS, the Pipelines will connect wells to be developed at approved sites where Operator has rights to drill New Wells on the property pursuant to an Amended and Restated Oil and Gas Operator Agreement ("**Operator Agreement**");

WHEREAS, the Operator Agreement shall be approved by City Council Resolution and executed contemporaneously with this Agreement and will have an effective date coinciding with the Effective Date of this Agreement;

WHEREAS, the Parties desire to enter into this Agreement to establish their respective rights and obligations with respect to the Surface Lands in accordance with the terms and provisions set forth herein, with such terms and provisions being expressly subject to the terms and conditions of the Operator Agreement entered into on even date herewith;

WHEREAS, all terms defined herein are intended to be consistent with the definitions set forth in the Operator Agreement and will have the definition set forth in the Operator Agreement, if available, and in the event of any inconsistency between the Operator Agreement and this Agreement, the Operator Agreement shall control; those terms not defined in the Operator Agreement but defined herein will have the definition set forth herein;

WHEREAS, Operator is the successor-in-interest to the Surface Use Agreement (the "**Prior SUA**") between the Surface Owner and Noble Energy, Inc., and approved by the City Council for the City and County of Broomfield on November 13, 2012, and recorded at Reception No. 2012014944 and is the successor-in-interest to a Use by Special Review ("**USR**") Permit that was approved by the City on July 12, 2011 and recorded at Reception No. 2011006781; and

WHEREAS, the City is willing to confirm and expressly convey to Operator rights to the Surface Lands as set forth herein.

NOW, THEREFORE, for and in consideration of the mutual covenants of the Parties and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties hereby agree as follows:

AGREEMENT

1. **Incorporation of Recitals**. The foregoing recitals are hereby incorporated by reference and the Parties agree that they are true and correct.

2. **Livingston Well and Lands Presently Subject to the Prior SUA**. Operator presently owns and operates the Livingston 43-7 Well generally located in the NE/4SE/4 of Section 7, Township 1 South, Range 68 West (the "**Livingston Well**"). The Livingston Well is located on lands subject to the Prior SUA as discussed in Recital D and in other provisions of the Prior SUA. The Parties agree that Operator may continue to operate, maintain and produce from the Livingston Well and related facilities, subject to the requirement to plug and abandon such well in accordance with Section 8 of the Operator Agreement. All provisions of the Prior SUA and the USR permit limited to those applicable to the operation of the Livingston Well and related facilities, including those provisions relevant to access, roads, flowlines and pipelines, and compliance with state and local regulations, will remain in full force and effect until such time as Operator plugs and abandons such well in accordance with Section 8 of the Operator Agreement. After the Effective Date, the development of any New Wells and related facilities on or near lands subject to the Prior SUA shall be governed by the terms of the Operator Agreement and by this Agreement.

3. **Surface and Subsurface Use Rights**. City hereby grants Operator the non-exclusive right for it, its agents, employees, and contractors, and their agents and employees, to enter upon and conduct Oil and Gas Operations, including the use of all required Facilities, upon the surface and subsurface of the City's Lands, as such Lands are more particularly described in **Exhibit A**. This grant shall be pursuant to the terms and conditions described herein and in accordance with the Operator Agreement. Any use of the Lands or Surface Lands by the Operator shall be limited to such uses.

4. **New Wells and Well Sites**. The locations of New Wells and all associated Facilities to be constructed on the Surface Lands on the Well Sites have been discussed in negotiations between the City and the Operator and have been defined and designated in the Operator Agreement. New Wells may only be located upon the Well Sites as generally shown on **Exhibit B**. The Operator shall have exclusive use of the Well Sites until all drilling and completion phases of the Operator's Oil and Gas Operations have been completed for each individual Well Site; provided, however, nothing in this Agreement shall limit any of the City's rights of entry and inspection of the Well Sites as set forth in the Operator Agreement. Once all drilling and completion phases have been completed on any individual Well Site, such Well Site shall automatically reduce to only such portions of the Surface Lands that are reasonably

required for the Operator to safely conduct the operational phase of its Oil and Gas Operations. Any portion of the Surface Lands removed from a Well Site ("Reclaimed Premises") shall be considered a Shared Premises in accordance with Section 5 herein; provided that, some or all of such Reclaimed Premises may be re-utilized by Operator on a temporary basis from time to time as necessary to conduct maintenance, workover, re-entry or other well work so long as any such Reclaimed Premises are again reclaimed in accordance with this Agreement following such temporary use. Operator shall have the right to locate, build, repair and maintain Facilities of the New Wells within the Well Sites, in accordance with the terms and conditions of the Operator Agreement.

5. **Shared Premises.** Each Party hereby agrees and consents to each other Party's right, on a non-exclusive basis, to the use and access of those certain portions of the surface of the Surface Lands (collectively, "**Shared Premises**"), that are not Well Sites, provided that such use by any Party shall remain subject to the terms of this Agreement.

6. **Pipelines, Gathering Lines, Lines and Flowlines.**

6.1 **Grant of Easement**. Surface Owner hereby grants, conveys and warrants to Operator, its agents, successors and assigns, a non-exclusive permanent and perpetual right-of-way and easement ("**Easement**") to enter upon the Surface Lands and occupy and use the areas described on **Exhibit C** (the "**Easement Area**"), subject to the Term as set forth in Section 15 of this Agreement. The Easements are subject to the terms, conditions and limitations herein and subject to all existing easements and rights-of-way and all existing Surface Owner improvements, if any, located on, over or under the Surface Lands and shall be Shared Premises under this Agreement. Operator shall cross existing Surface Owners rights-of-way at the designated locations. The route and course of the right-of-way and easement granted and conveyed are more particularly described on **Exhibit C**. The width of the Easement Area shall be one-hundred feet (100') during initial construction and during subsequent repairs, replacement, relocation, rebuilding, reconstruction, or removal of the Lines (as defined below) and, at all other times, the width of the Easement Area shall be thirty feet (30'). In consideration for the grant of the Easement, Operator shall make a cash payment to the Surface Owner in an amount equal to $20.00 per linear foot for the length of the Easement Area within the Open Space and there shall be no payment for use of the Easement Area within the Open Lands.

6.2 **Scope of Easement**. The Easement granted to Operator is limited in scope to the following permitted rights: to survey, lay, place, travel across, use, construct, maintain, inspect, operate, repair, replace, relocate, modify, rebuild, change the size of, reconstruct, mark, monitor, abandon, remove and reclaim a pipeline and/or transmission line system consisting of one or more pipelines, electric power lines, equipment and appurtenances (collectively, the "**Lines**"), all of which shall be below ground, for the transportation or transmission of oil, gas, petroleum products, produced water, electricity, hydrocarbons and any other substances, whether electronic, fluid, solid or gaseous, and any products, derivatives, combinations or mixtures of any of the foregoing, in, on, over, under, or through the Easement Area except for the fresh water line that will carry fresh

water above ground from the Weber H Unit 1 Well Pad, which was approved by the City on February 12, 2013 for a use by special review permit by Resolution No. 2013-22, to the New Well Sites. Operator shall have all rights, privileges and benefits necessary or convenient for the full use and enjoyment of this Agreement, including but not limited to, the right of ingress and egress in, to, over and through the Surface Lands for the exercise of each of the permitted rights granted herein and in the Operator Agreement, as well as the right to maintain, add to, increase or decrease the diameter of any replacement Lines, modify, repair, replace or remove the Lines, and to replace all or any part of the Lines or any portion thereof by first laying replacement Lines.

6.3. **Temporary Work Easement**. During the initial and any subsequent construction of the Lines, Surface Owner does hereby grant to Operator the right, as reasonably needed from time to time, to additional temporary workspace on and adjacent to the Surface Lands in order to access, travel across, use, survey, construct, maintain, inspect, operate, repair, alter, replace, modify, change the size of, reconstruct, mark, monitor, abandon or remove the Lines or install additional equipment or appurtenances. Operator will require one-hundred feet (100') feet in width of temporary work easement in order to complete the necessary work to bury the Lines at least 48 inches beneath the surface and complete other repairs, replacement, relocation, rebuilding, reconstruction, or removal of the Lines. Operator may install and operate temporary Lines on the surface while permanent Lines are being constructed, repaired, or maintained. Any temporary surface Lines shall be limited in use, and shall not be used for any period of greater than 90 days without the express written authorization of the City.

6.4. **Limitations of Use**. Operator acknowledges and agrees that City utilizes the Surface Lands for its water line (the "**Water Line**"), and that any Lines installed by Operator hereunder shall be separated from Surface Owner's Water Line. City retains the right to the use and occupancy of the Easement Area insofar as such use and occupancy is consistent with and does not in any way interfere with or impair the rights herein granted. Operator agrees that its use of the Easement Area is non-exclusive and that other uses, including pipelines and utilities, may be installed in the Easement Area as long as such uses do not interfere with Operator's rights as herein granted. City agrees not to build, construct, or permit to be built or constructed any building, fence, landscaping, reservoir, engineering works, or other structures or improvements over, under or across the Easement Area which may interfere with the Operator's use of the Easement Area without prior written consent of Operator which consent will not be unreasonably withheld. The Parties acknowledge that City may use the Easement Area for public access and may construct an access drive, fence, landscaping, signs, sidewalk, or trail upon or within the Easement Area provided such improvements do not interfere with the Operator's use of the Easement Area.

Lines shall be placed on certain specified locations called "**Line Easements**", which are depicted on **Exhibit C**. Any deviation of the location of the Line Easements shall be mutually agreed upon in writing giving due consideration to utilizing the most direct economic routing and such agreement shall not be unreasonably withheld,

conditioned or delayed. If any Lines require relocation at City's written request, City shall provide written notice of the request with an alternative route and allow a reasonable amount of time for Operator to construct the alternative Line route and tie in. Operator may not object to any such relocation so long as relocation is reasonable and feasible from a technical and engineering standpoint and complies with all applicable rules and regulations and received notice and the time to construction the alternative route. All such relocations shall be at City's cost and expense as hereafter described. Operator shall abandon any portion of a Line, Easement Area, or Line Easements that will no longer be used for its operations. All abandoned flowlines or pipelines shall be abandoned in accordance with the Operator Agreement, the COGCC, and local, state and federal regulations. Additionally, Operator will provide notice to the City in writing of the abandonment and a map showing the location of the abandoned pipeline.

6.5 **Power Lines**. Operator will consult with City and, if applicable, with an independent power company supplying power to Operator with respect to the location of power lines prior to construction. All power lines will be underground in accordance with City policy.

7. **Access Roads**.

7.1 **Access Roads**. City agrees to allow Operator to construct new access roads or improve existing access roads on the Surface Lands at Operator's own expense (the "**Access Roads**"). The Access Roads shall be on the locations depicted on **Exhibit C**.

7.2 **Existing Access Roads**. With respect to Access Roads existing as of the Effective Date, Operator shall maintain such Access Roads in at least as good or better condition as such roads are found prior to Operator's use. The Operator retains the right to abandon use of an Access Road at any time. There will not be any additional consideration for use of the Access Roads.

7.3 **Grant of Easement**. Owner hereby grants to Operator, its successors and assigns, a non-exclusive right-of-way and easement over and across the Surface Lands for purposes of vehicular and pedestrian ingress, egress and regress. The location of the right-of-way and easement is more particularly described and shown on the survey included on **Exhibit C** (the "**Road Access Area**"). The Road Access Area shall be a Shared Premises under this Agreement.

7.4 **Maintenance**. Operator shall have the financial responsibility for maintenance of the Access Roads. Maintenance of the Access Roads shall include the use of preventive measures as are necessary to mitigate dust and maintain the surface of the Access Roads in a level, smooth and evenly-covered condition with the type of surfacing material originally installed or such substitute as shall in all respects be equal in quality, use, and durability.

7.5 **No Interference with Use**. Neither Party shall use the Access Roads in

any manner that would interfere with or be inconsistent with the other Party's use thereof. The Parties acknowledge that the City may use the Access Roads for authorized City use and shall also be permitted to allow use otherwise in accordance with City regulations for Open Space and Open Lands, as applicable, provided that such use does not interfere with the Operator's use of the Access Roads. The Parties acknowledge that the City shall be permitted to construct fencing, landscaping, signage, sidewalks or trails adjacent to the Access Roads.

8. **Location of New Wells, Access Roads and Facilities**. The City and the Operator have discussed the locations of New Wells, the Access Roads and all associated Facilities to be constructed on the Surface Lands and shall be located as provided in the Operator Agreement or this Agreement.

9. **Modifications and Variances Affecting Surface Use**. Modifications and variances to the designated Oil and Gas Operations areas may be required from time-to-time at the request of the Surface Owner or the Operator. The Operator agrees to consider such variances or modifications to COGCC rules, Broomfield Municipal Code or other law as requested by the Surface Owner for surface use pursuant to this Agreement and agrees to prepare the modification or variance requests according to the applicable rules, regulation and laws. The Surface Owner also agrees to consider the Operator's requests for modifications or variances sought by Operator, with consent to such requests to not be unreasonably withheld, conditioned or delayed. It is also understood and agreed that additional Access Roads and Facilities located outside of the designated operating areas may be necessary for Operator's activities and in these circumstances Surface Owner and Operator agree to designate a mutually agreeable location for said Access Roads and Facilities. Operator agrees not to use any more of the surface of the Surface Lands than is reasonably necessary to conduct its operations.

10. **Best Management Practices**. The Oil and Gas Operations on the Well Sites shall be conducted in accordance with the BMPs set forth in **Exhibit B** to the Operator Agreement.

11. **Reclamation**. Operator shall reclaim any disturbed areas in accordance with the terms of the Operator Agreement.

12. **Conduct of Operations**. Operator's operations on the Surface Lands will be conducted pursuant to the terms of this Agreement, the Operator Agreement, the rules and regulations of the COGCC, applicable Colorado statutes and case law, and any applicable federal statutes and case law. This Agreement does not grant or otherwise vest in the Surface Owner a private right to enforce the rules and regulations of the COGCC or any other state statute, rule or law.

13. **City's Cooperation and Assistance with Operator's Other Regulatory Filings.** In the Operator Agreement and this Agreement, the City and Operator have reached agreement

on the location and other matters relating to designated Well Sites from which the Operator may drill, complete, and operate New Wells. The Operator Agreement and this Agreement also, among other things, established BMPs and other comprehensive processes by which the Operator will provide advance notice to the City of proposed oil and gas operations and otherwise work with the City as those operations move forward. As a result, the City agrees that, so long as Operator is in compliance with the terms of the Operator Agreement and this Agreement:

(a) the City hereby waives any right it may have under COGCC Rules or other law, as presently enacted or amended in the future, to receive advance notice of, or consult with the Operator about, proposed oil and gas operations subject to this Agreement. This waiver includes, but is not limited to, a waiver of the City's right, if any, to receive notice and consult with the Operator as provided in COGCC Rules 305, 305A and 306. The City agrees that the Operator may submit a copy of this Agreement to the COGCC as evidence of this waiver by the City.

(b) the City hereby waives any right it may have under COGCC rules or other law, as presently enacted or amended in the future, to protest or otherwise object to any permit application or other regulatory filings by Operator with the COGCC or any other government. This waiver includes, but is not limited to, a waiver of the City's right, if any, to receive notice and consult with the Operator as provided in COGCC Rule 303. The City agrees that the Operator may submit a copy of this Agreement to the COGCC as evidence of this waiver by the City.

(c) the City hereby waives any right it may have under COGCC rules or other law, as presently enacted or amended in the future, to protest or otherwise object to any setback proposed for a New Well by Operator with the COGCC or any other government. This waiver includes, but is not limited to, a waiver of the City's right, if any, to receive notice and consult with the Operator as provided in COGCC Rule 603. The City agrees that the Operator may submit a copy of this Agreement to the COGCC as evidence of this waiver by the City.

14. **Surface Use Payment**. The Parties acknowledge that prior compensation has been paid by Operator for surface use hereunder of the Livingston Well Site. The Parties intend that, in exchange for Operator's surface use hereunder of the Northwest & United Well Sites, which are designated as open space lands by the City, that Operator will convey to the City approximately thirty-nine (39) acres of other lands, as described in more detail on **Exhibit D** (the "**Exchange Lands**"), and the cash payment of a surface damage payment in the amount of $650,000 (the "**Cash Payment**") and the Operator will execute a special warranty deed no later than March 1, 2018 to convey the Exchange Lands to the City (the "**Conveyance Agreement**"), a form of which is attached hereto as **Exhibit E**. Operator will apply for a minor subdivision with the City to allow for a conveyance of the Exchange Lands to the City. City Council for the City has approved this Agreement at a public meeting through Resolution and has determined that the Exchange Lands and the Cash Payment are just compensation for Operator's surface use hereunder of the Northwest & United Well Sites and for the other use of the Surface Lands set forth in this Agreement.

15. **Term, Abandonment and Reclamation.** This Agreement will be effective upon City Council's approval by resolution and signature by both Parties (the "**Effective Date**"), and will continue in full force and effect as long as the Operator has operations or owns or controls wells at the Well Sites and has Oil and Gas Operations at the Well Sites ("**Term**"), unless and until terminated as herein provided or unless otherwise terminated by law. The Term shall be extended if it is necessary for the Operator to access the Surface Lands to plug and abandon the New Wells and to reclaim the Surface Lands as provided in this Agreement and for such other purposes as necessary to comply with the BMPs, the rules and regulations of the COGCC or any other government or other law. The Term of the Agreement will hereby continue until such wells are plugged and the land is reclaimed consistent with the BMPs, the rules and regulations of the COGCC or any other government or other law. The provisions of Section 23 shall survive following the end of the Term.

16. **Limitations on Use.** Operator shall not commit or permit any waste, injury or nuisance upon the Surface Lands, and shall not use or permit the Surface Lands to be used for any purpose contrary to state or federal law.

17. **Taxes.** Surface Owner shall pay any property taxes or taxes attributable to the Surface Lands assessed, due and payable against the Surface Lands during the Term of this Agreement.

18. **Surface Lands Excluded from New Special Taxing Districts**. To the extent not prohibited by law, the City and Operator agree that the City shall not take any affirmative action to approve, without Operator's written consent, the inclusion any of the Well Sites or any of the Surface Lands used by Operator for Oil and Gas Operations in any new or materially modified special districts or limited purpose governmental entities organized pursuant to the Colorado Special District Act, Article 1 of Title 32 of the Colorado Revised Statutes, or any other similar Colorado statutes or laws.

19. **Mineral Lands Excluded from New Special Taxing Districts**. Operator represents that, at present, it owns certain oil and gas leasehold or other mineral interests in the Lands (the "**Minerals**"). To the extent not prohibited by law, the City and Operator agree that the City shall not take any affirmative action to approve, without Operator's written consent, the inclusion of the Well Sites or any of the Minerals in any new or materially modified special districts or limited purpose governmental entities organized pursuant to the Colorado Special District Act, Article 1 of Title 32 of the Colorado Revised Statutes, or any other similar Colorado statutes or laws.

20. **Representations**. Each Party represents that it has the full right and authority to enter into this Agreement, and Surface Owner specifically confirms its capacity to validly execute the rights of way and easements provided herein. Surface Owner represents that it owns certain oil and gas leasehold interests on the Lands. Operator represents, and specifically asserts, that it does not have the right to bind any other oil and gas leasehold interest owner, mineral owner, lessee, or assignee for the Property.

21. **Successors and Assigns.** The Parties may transfer their respective rights or

interests in the Surface Land. No Party shall assign, sublet, mortgage, or otherwise transfer or encumber this Agreement or any right or privilege contemplated herein, without the prior written consent of each other Party hereto, which consent shall not be unreasonably withheld, conditioned or delayed. This Agreement constitutes an easement, right-of-way, and covenant running with the Surface Lands and will be binding upon and inure to the benefit of, and be enforceable by, the Parties and their respective successors, affiliates, administrators, trustees, executors, and assigns.

22. **Notices.** Any notice or other communication required or permitted under this Agreement shall be given in writing either by i) personal delivery; ii) expedited delivery service with proof of delivery; or iii) United States Mail, postage prepaid, and registered or certified mail with return receipt requested, addressed as follows:

If to OPERATOR:

Extraction Oil & Gas, Inc.
370 17th Street, Suite 5300
Denver, CO 80202
Attention: Land Department

If to SURFACE OWNER:

City & County Manager
City and County of Broomfield
One DesCombes Dr.
Broomfield, CO 80020

with a copy to:

City & County Attorney
City and County of Broomfield
One DesCombes Dr.
Broomfield, CO 80020

Any Party may, by written notice so delivered to the other Party, change the address or individual to whom delivery shall thereafter be made.

23. **Indemnification and Hold Harmless Provisions**.

a. **Each Party Responsible for Its Operations/Ownership**. Each Party shall be and remain responsible for all losses, claims, damages, demands, court awards, suits, causes of action, fines, penalties, expenses and liabilities, including without limitation, attorneys' fees and other costs associated therewith (all of the foresaid collectively referred to "**Claims**"), arising out of or connected with each such Party's ownership or operations on the Surface Lands, regardless of when asserted, subject to

statute of limitations. The provisions in this section do not, and shall not be construed to, create any rights in persons or entities not a party to this Agreement, nor does it create any separate rights in Parties to this Agreement, other than the right to be indemnified or held harmless for Claims as specifically provided herein.

b. **Operator's Hold Harmless, Indemnity and Release Agreement**. Operator shall release, defend, indemnify and hold the City and its Representatives harmless against all Claims that are threatened or awarded or incurred as a result of any loss, injury or damage sustained or claimed to have been sustained by anyone including, but not limited to, any person, firm, partnership, or corporation arising out of any action, inaction or act of commission by the Operator or any of its Representatives in the Operator's operations on or development of the Surface Lands to the extent the Claim is attributable to the action, inaction or act of commission of the Operator or its Representatives. This hold harmless provision running from the Operator to the City applies to all matters, including Environmental Claims (as defined below).

c. **Environmental Claims**. "**Environmental Claims**" shall mean all Claims asserted by the City, governmental bodies or other third parties for pollution or environmental damage of any kind, arising from Oil and Gas Operations on or ownership of Surface Lands or ownership of oil and gas interests or oil and gas leasehold interests by the Operator on the Surface Lands, whichever is applicable, and all cleanup and reclamation and/or remediation costs, fines and penalties associated therewith, including any Claims arising from any federal or state environmental laws. Environmental Claims shall not include the costs of any remediation undertaken voluntarily by any Party, unless such remediation is performed under the imminent threat of a Claim by a governmental body or other third party.

d. **Release**. Operator hereby releases, waives and discharges the City and its Representatives (the "**City Group**") from any and all liability for personal injury, death, property or other damage, or otherwise arising out of Operator's Oil and Gas Operations, actions, inactions or act of commission of the Operator or its Representatives under this Agreement, unless such injury, death or damage is the result of the City's negligence or willful misconduct or that of a member of the City Group.

e. **Exclusion from Indemnities and Hold Harmless Provisions**. The indemnities or hold harmless agreements of the Parties in this section shall not cover or include any amounts which the indemnified Party is actually reimbursed for by any third party. The indemnities in this Agreement shall not relieve any Party from any obligations to third parties.

24. **Injunctive Relief.** No section of this Agreement shall restrict either Party's right to seek injunctive relief or specific performance. Each Party shall be entitled to enforce specifically the terms and provisions of this Agreement in addition to any other remedy to which such holder may be entitled at Law, in equity, or otherwise.

25. **Further Assurances**. The Parties agree to execute and deliver such other documents as are reasonably necessary in order to effectuate the terms and intent of this Agreement.

26. **Governing Law.** This Agreement shall be governed by and construed in accordance with the laws of the State of Colorado. The Parties waive the right to trial by jury with respect of any action, suit, or proceeding arising out of or relating to this Agreement or any contemplated transaction.

27. **Insurance.** Operator shall maintain insurance at all times during the Term of this Agreement in accordance with the terms and conditions set forth on **Exhibit H** to the Operator Agreement.

28. **Third-Party Beneficiaries**. Nothing herein, express or implied, is intended to or does confer upon any other person or entity any legal or equitable right, benefit or remedy of any nature whatsoever under or by reason of this Agreement.

29. **Binding Effect**. This Agreement, all provisions, and the covenants and conditions herein contained shall be binding upon and inure to the benefit of the parties hereto and their respective transferees, successors, and assigns. Surface Owner agrees to contact any and all tenants of Surface Lands or other third parties utilizing the surface of the Surface Lands that may be affected by Operator's activities on the Surface Lands. It will be Surface Owner's sole responsibility to advise such third parties of the existence of this Agreement and Operator's right to utilize the surface of the Surface Lands pursuant to this Agreement for the payment of any consideration, if any, due such third party from Surface Owner.

30. **Recording**. The Parties agree Operator may record this Agreement in the real estate records of City and County of Broomfield, Colorado.

31. **Entire Agreement**. This Agreement and all its attachments, together with the Conveyance Agreement, Operator Agreement, Pipeline Easement Agreement and Settlement Agreement (the "**Other Agreements**") constitute the complete and exclusive statement of the entire understanding between and among the Parties regarding the matters addressed herein. This Agreement supersedes any prior agreements or understandings regarding the matters addressed herein, whether written or oral. In the event that there are conflicting terms between this Agreement and the Other Agreements, the terms of this Agreement shall control. This Agreement and the Other Agreements include all the agreements and stipulations between the Parties, and no representations, oral or written, have been made, modifying, adding to, or changing the terms hereof.

32. **Non-Waiver**. Waiver by either Party or of the failure of any Party to insist upon the strict performance of any provision of this Agreement shall not constitute a waiver of the right or prevent any such Party from requiring the strict performance of any provision in the future.

33. **Reasonable Accommodation**. Surface Owner acknowledges the use of the Surface Lands by Operator as herein described in in full satisfaction of the requirement that Operator conduct its Oil and Gas Operations in a manner that accommodates Surface Owner. Surface Owner further acknowledges Operator's use of the Surface Lands as provided herein constitutes "reasonable accommodation" by Operator, its successors, and assigns as provided in Colorado Revised Statute 34-60-127.

34. **Relationship of the Parties**. This Agreement shall not be construed to create an association, partnership, joint venture, employment or other agency relationship between the Parties. No Party is now, nor will any Party be construed to be, an employee, contractor, partner, joint venturer, agent or representative of any other party for any purpose under this Agreement.

35. **Amendments**. No modification or amendment of this Agreement shall be valid or binding unless the same is in writing and duly executed by all Parties hereto.

36. **Severability**. If any term or other provision of this Agreement is invalid, illegal, or incapable of being enforced by any rule, law or public policy, all other conditions and provisions of this Agreement shall nevertheless remain in full force and effect so long as the economic or legal substance of the transactions contemplated hereby is not affected in any adverse manner to either Party. Upon such determination that any term or other provision is invalid, illegal, or incapable of being enforced, the Parties shall negotiate in good faith to modify this Agreement so as to effect the original intent the Parties as closely as possible in an acceptable manner to the end that the transactions contemplated hereby are fulfilled to the extent possible.

37. **Force Majeure**. If any Party is rendered unable, wholly or in part, by Force Majeure (as defined in the Operator Agreement) to carry out its obligations under this Agreement, that party shall give to the other Party prompt written notice of the Force Majeure with reasonable full particulars concerning it; thereupon, the obligations of the party giving the notice, so far as they are affected by the Force Majeure, shall be suspended during, but no longer than, the continuance of the Force Majeure.

The affected Party shall use all reasonable diligence to remedy the Force Majeure situation as quickly as possible and practicable. The requirement that any Force Majeure shall be remedied with all reasonable dispatch shall not require the settlement of strikes, lockouts, or other labor difficulty by the party involved, contrary to its wishes; how all such difficulties shall be handles shall be entirely within the discretion of the Party concerned.

38. **Counterparts**. This Agreement may be executed in any number of counterparts, and each such counterpart hereof shall be deemed to be an original instrument, but all of such counterparts shall constitute for all purposes one agreement. Any signature hereto delivered by a party by facsimile transmission or other electronic transmission shall be deemed an original signature hereto.

39. **References; Rules of Construction**. All references in this Agreement to

Exhibits, Sections, subsections, and other subdivisions refer to the corresponding Exhibits, Sections, subsections, and other subdivisions of or to this Agreement unless expressly provided otherwise. Titles appearing at the beginning of any Sections, subsections, and other subdivisions of this Agreement are for convenience only, do not constitute any part of this Agreement, and shall be disregarded in construing the language hereof. The words "this Agreement," "herein," "hereby," "hereunder," and "hereof," and words of similar import, refer to this Agreement as a whole and not to any particular Article, Section, subsection, or other subdivision unless expressly so limited. The word "including" (in its various forms) means including, without limitation. Pronouns in masculine, feminine, or neutral genders shall be construed to state and include any other gender, and words, terms, and titles (including terms defined herein) in the singular form shall be construed to include the plural and vice versa unless the context otherwise requires. Except as expressly provided otherwise in this Agreement, references to any law or agreement means such law or agreement as it may be amended from time to time.

40. **Authority of Signatories.** The signatories below declare, warrant and represent that they have the authority to enter into this Agreement on behalf of their respective principals, if any.

41. **Effective Date**. This Agreement shall become effective on the Effective Date upon the execution of this Agreement by all Parties hereto and upon the approval of this Agreement by Resolution of the City Council.

42. **Headings**. The section headings contained herein are for convenience in reference and are not intended to define or limit the scope of any provision of this Agreement.

43. **Construction**. The Parties have participated jointly in the negotiating and drafting of this Agreement. In the event ambiguity or question of intent or interpretation arises, this Agreement shall be construed as if drafted jointly by the Parties, and no presumption or burden of proof shall arise favoring or disfavoring any Party by virtue of the authorship of any of the provisions of this Agreement. Any reference to any federal, state, local or foreign statute or law shall be deemed also to refer to all rules and regulations promulgated thereunder, unless the context requires otherwise. The word "including" shall mean including, without limitation.

[Signature page to follow]

IN WITNESS WHEREOF, Surface Owner and Operator have executed, agreed to and delivered this Surface Use Agreement as of the Effective Date.

SURFACE OWNER:

THE CITY AND COUNTY OF BROOMFIELD, COLORADO,
A Colorado Municipal Corporation and County

Mayor

CITY & COUNTY OF BROOMFIELD SEAL COLORADO

ATTEST:

City & County Clerk

APPROVED AS TO FORM:

City & County Attorney Deputy

OPERATOR:

EXTRACTION OIL & GAS, INC.

Eric J. Christ, Vice President, General Counsel & Corporate Secretary

State of Colorado)
)ss.
County of Broomfield)

The foregoing instrument was acknowledged before me this 25TH day of October 2017 by Eric J. Christ, Vice President of Extraction Oil & Gas, Inc.

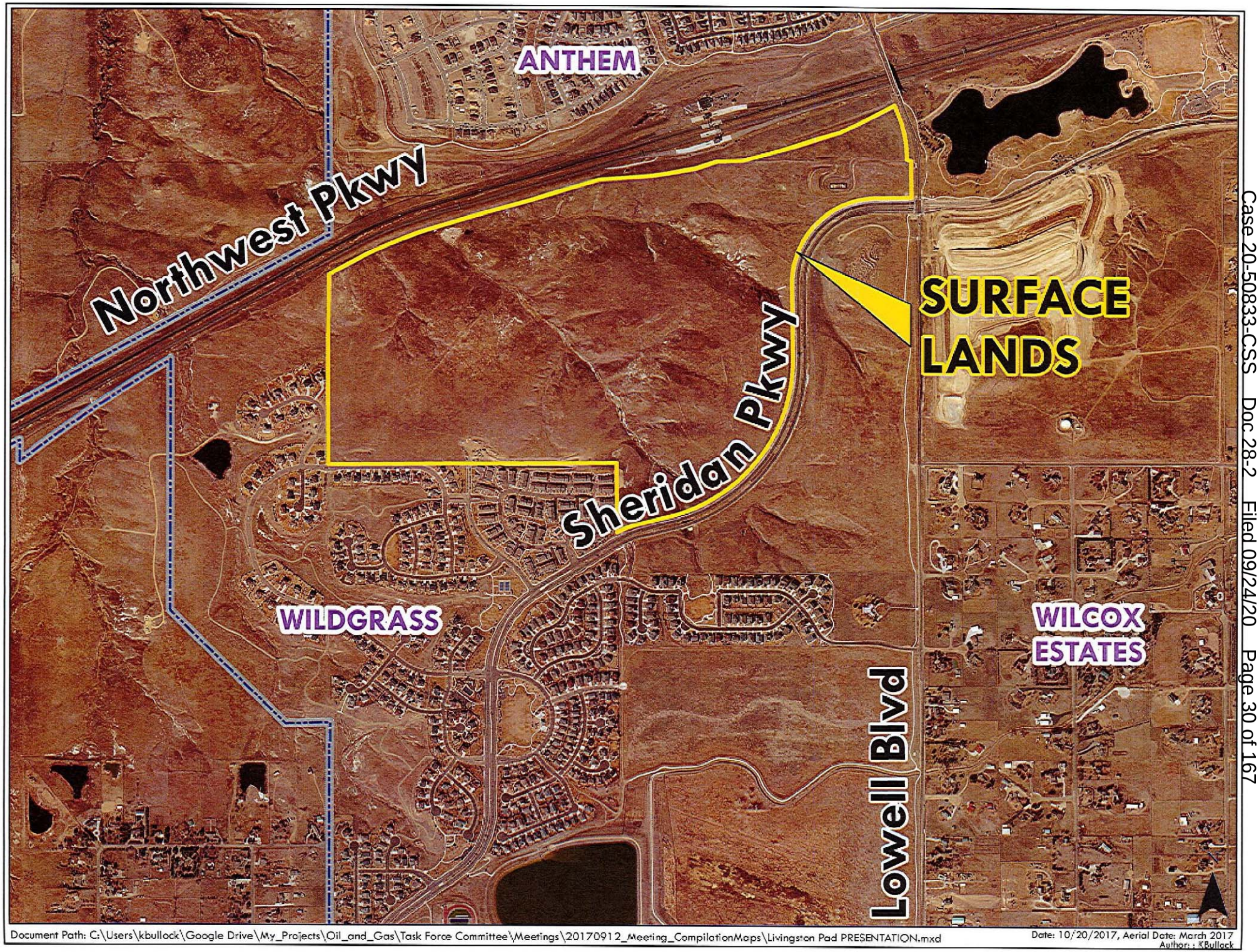
Notary Public

My Commission expires: October 7, 2021 (Seal)

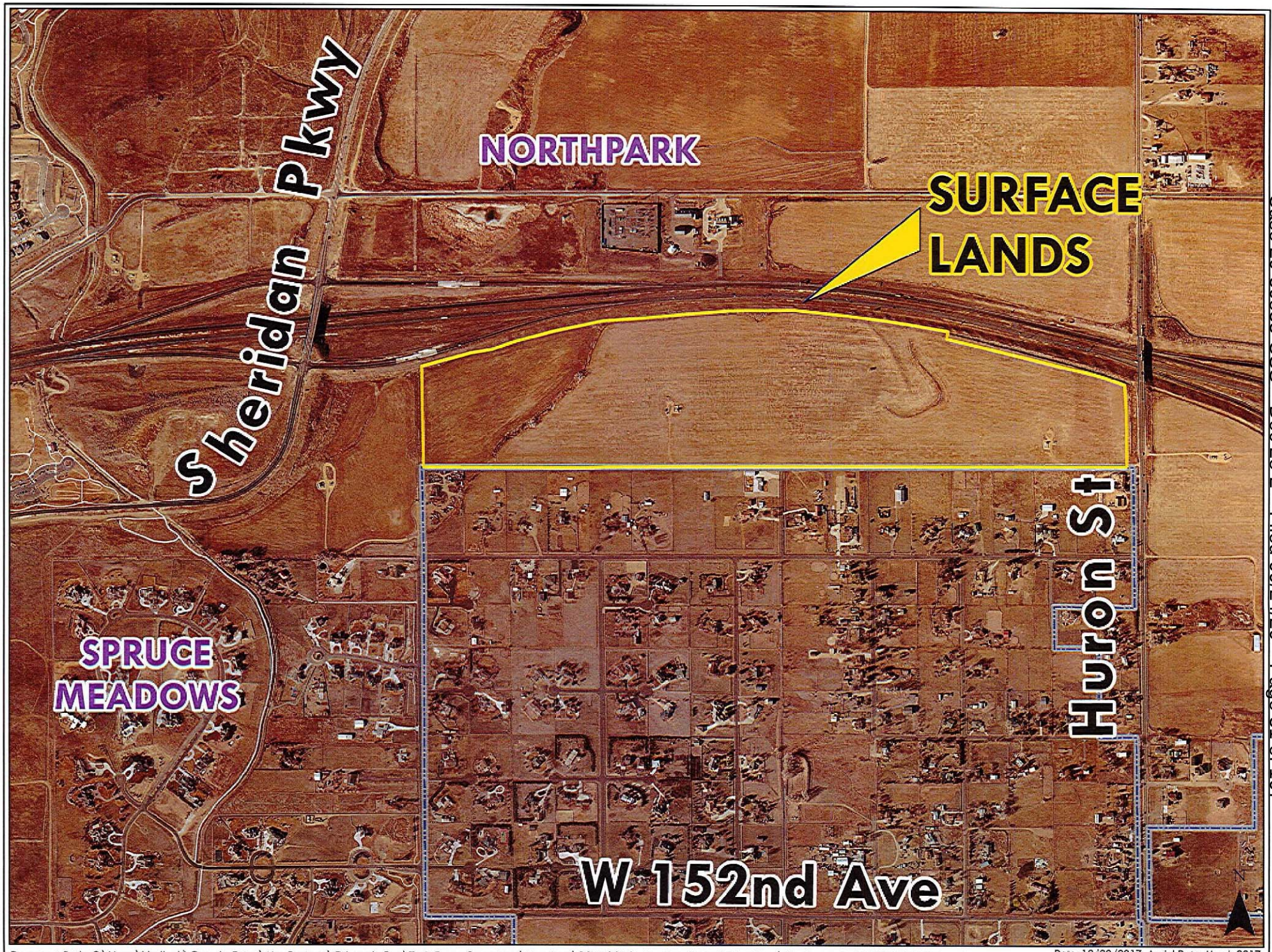
LINDA J. VILLAREAL
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20134063200
My Commission Expires Oct. 7, 2021

EXHIBIT A

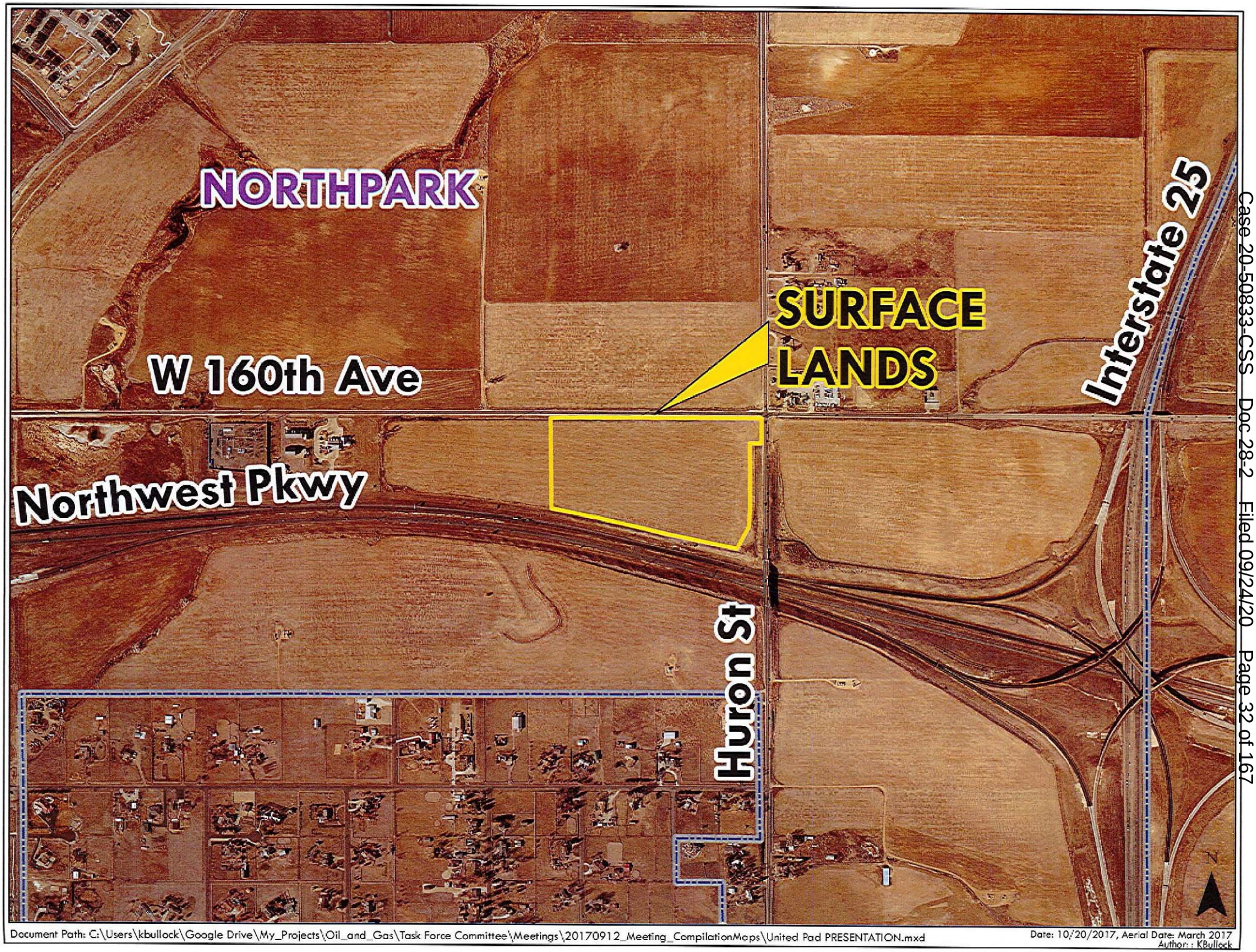
Map of Surface Lands



Case 20-50833-CSS Doc 28-2 Filed 09/24/20 Page 30 of 167



Case 20-50833-CSS Doc 28-2 Filed 09/24/20 Page 31 of 167



Case 20-50833-CSS Doc 28-2 Filed 09/24/20 Page 32 of 167

EXHIBIT B

Map of Well Sites

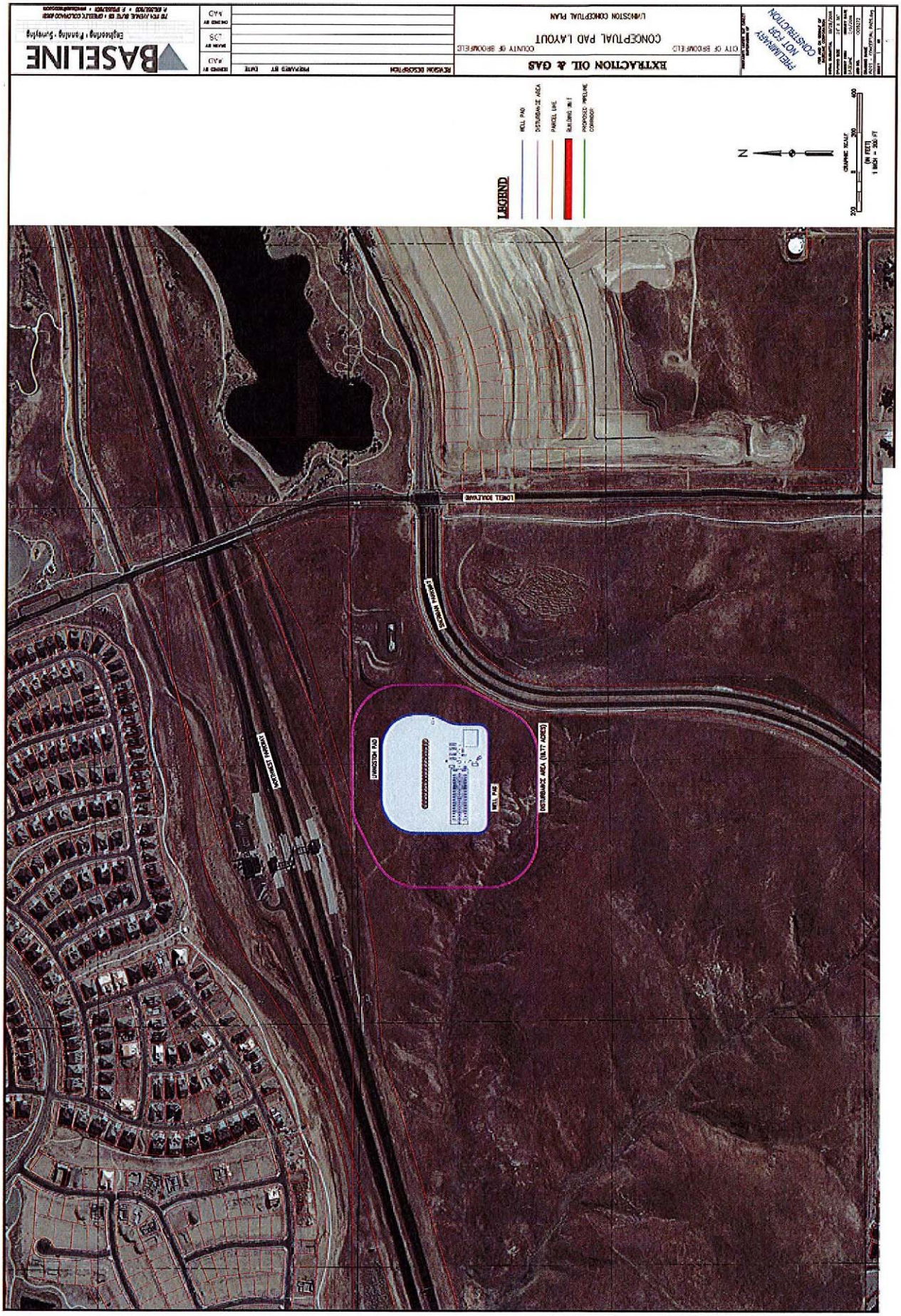


EXHIBIT B

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PlatteRiver_006065



EXHIBIT B

PlatteRiver_006066

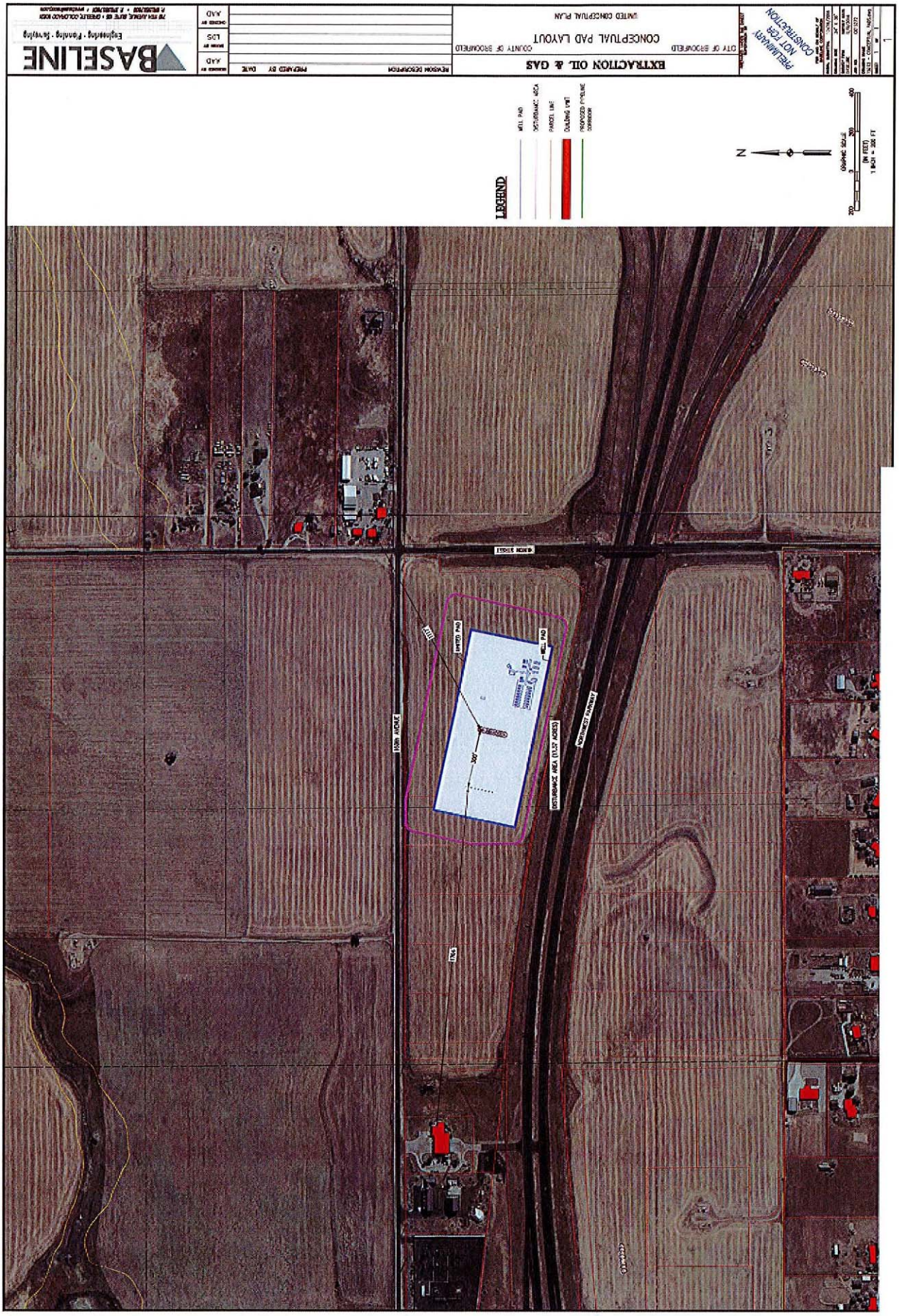
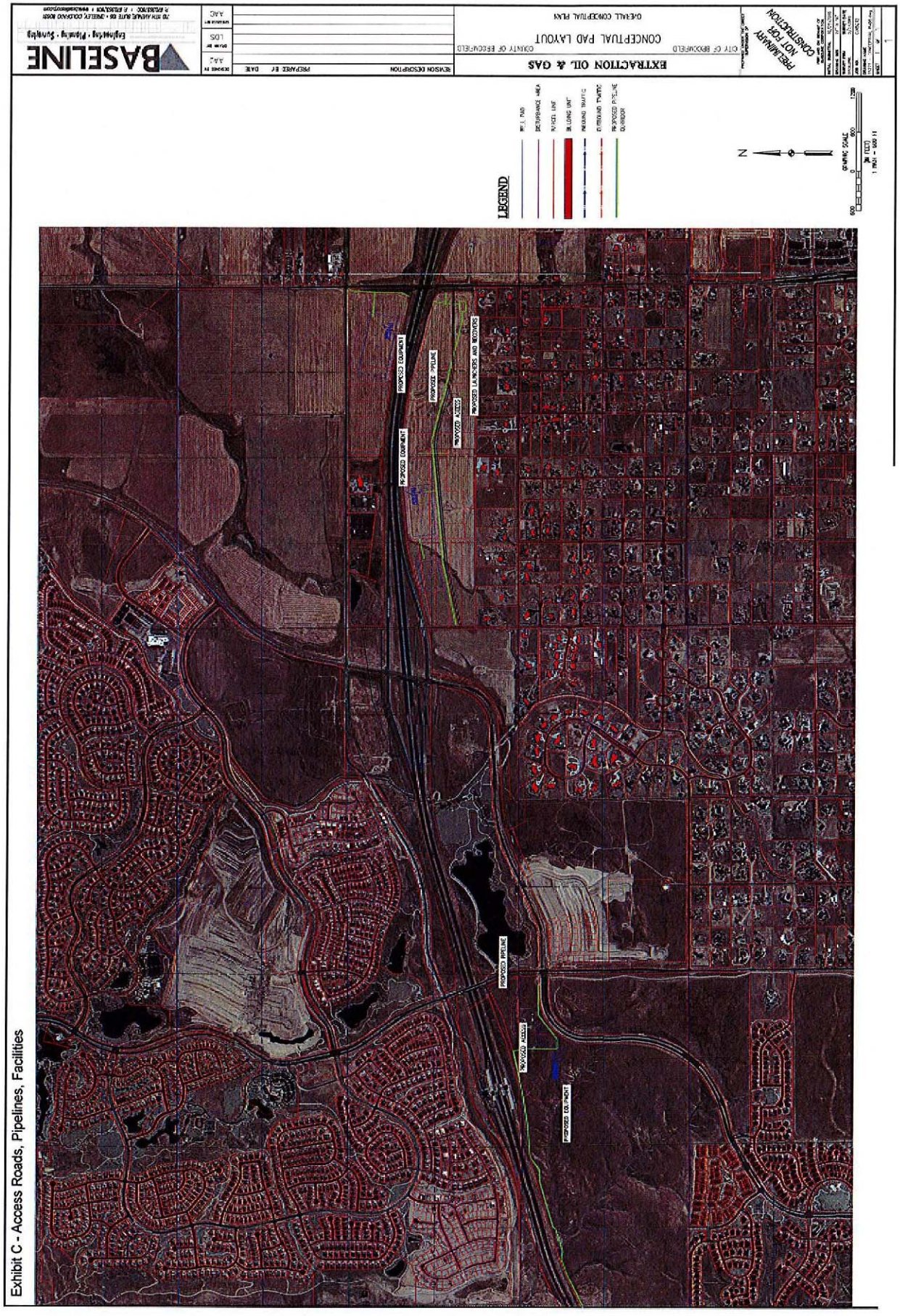


EXHIBIT B

PlatteRiver_006067

EXHIBIT C

Access Roads, Pipelines and Facilities



PlatteRiver_006069

EXHIBIT D

Exchange Lands

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EXHIBIT D



PlatteRiver_006071

EXHIBIT E

Conveyance Agreement

SPECIAL WARRANTY DEED

THIS SPECIAL WARRANTY DEED, made this ____ day of _____, 2017 by and between_____-("Grantor"), whose legal address is _____, and the CITY AND COUNTY OF BROOMFIELD, COLORADO, a Colorado Municipal Corporation and County pursuant to the laws of the State of Colorado ("Grantee"), whose legal address is One DesCombes Drive, Broomfield, Colorado, 80020.

WITNESSETH, That the Grantor, for and in consideration of the sum of Ten and No/100 Dollars ($10.00) and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, has granted, bargained, sold and conveyed, and by these presents does grant, bargain, sell, convey, and confirm, with covenants of special warranty unto the Grantee, the Grantee's successors and assigns, forever, the surface estate that Grantor owns, situated, lying and being in Broomfield County, State of Colorado (the "Real Property"), described in exhibit "A" attached hereto and incorporated herein by this reference.

EXCEPTING AND RESERVING, unto the Grantor, all of Grantor's right title and interest in and to all of the oil, gas, and other minerals in, under, and that may be produced from the Real Property.

TOGETHER with all and singular the hereditaments and appurtenances thereto belonging, or in anywise appertaining, and the reversion and reversions, remainder and remainders, rents, issues and profits thereof, and all estate, right, title, interest, claim and demand whatsoever of the Grantor, either in law or equity, or, in and to the above gifted Real Property, with the hereditaments and appurtenances.

TO HAVE AND TO HOLD the said Real Property above gifted and described with the appurtenances, unto the Grantee, the Grantee's heirs and assigns forever. And the Grantor, for itself, and its successors, does give, covenant, grant, convey and agree to and with the Grantee, the Grantee's heirs and assigns, that at the time of the ensealing and delivery of these presents, it is well seized of the Real Property above conveyed, has good, sure, perfect, absolute and indefeasible estate of inheritance, in law, in fee simple, and has good right, full power and authority to give, grant, and convey the same in manner and form as aforesaid, and that the same are free and clear from all former and other grants, bargains, sales, liens, taxes, assessments, encumbrances and restrictions of whatever kind or nature whatsoever, except the "Permitted Conditions, Encumbrances and Restrictions" as set forth in Exhibit "B" attached hereto and incorporated herein by this reference.

The Grantor shall and will WARRANT AND FOREVER DEFEND the Real Property in the quiet and peaceable possession of Grantee, its successors and assigns, against all and every person or persons claiming the whole or any part thereof BY, THROUGH OR UNDER Grantor.

IN WITNESS WHEREOF, Grantors have executed this SPECIAL WARRANTY DEED on the date indicated below.

GRANTOR:

Date:_____ _____

STATE OF COLORADO)

)ss

COUNTY OF _____)

The foregoing instrument was acknowledged before me this _____ day of _____ 2017, by _____.

Witness my hand and official seal.

(SEAL)

_____

Notary Public

My commission expires _____

EXHIBIT A
Legal Description

EXHIBIT B

Permitted Conditions, Encumbrances and Restrictions

PlatteRiver_006077

EXTRACTION OIL & GAS

CONCEPTUAL PAD LAYOUT

ACCESS REVISED CONCEPTUAL PLAN

CITY OF BROOMFIELD COUNTY OF BROOMFIELD

PRELIMINARY NOT FOR CONSTRUCTION

BASELINE Engineering • Planning • Surveying



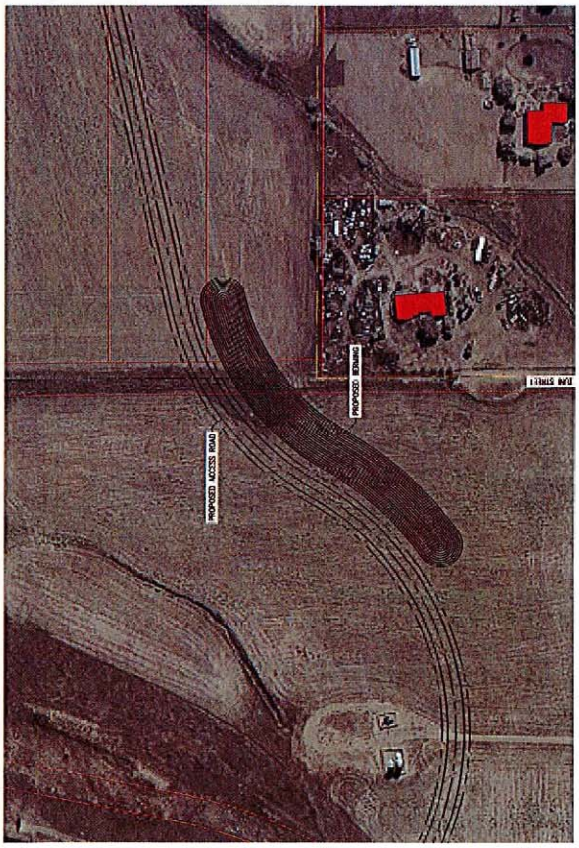


EXHIBIT I

SETTLEMENT AGREEMENT
GENERAL RELEASE AND WAIVER OF CLAIMS

This SETTLEMENT AGREEMENT, GENERAL RELEASE AND WAIVER OF CLAIMS (the "Settlement Agreement") is entered into this 24th day of October 2017, by and among the City and County of Broomfield ("City"), and Extraction Oil & Gas, Inc. ("Extraction" or "Operator"). The City and Operator are sometimes referred to herein individually as a "Party" and collectively as the "Parties."

WHEREAS, Operator and its predecessors-in-interest entered into agreements with the City to develop oil and gas within the City limits, including an Oil and Gas Operator Agreement dated August 27, 2013, and recorded at Reception No. 2013015088; a Supplement to the Oil and Gas Operator Agreement executed by the Parties on June 14, 2016, effective August 27, 2013, and recorded at Reception No. 2016007563; a Surface Use Agreement between the City and Noble Energy, Inc., approved by the City on November 13, 2012, and recorded at Reception No. 2012014944 and a Use by Special Review Permit that was approved by the City on July 12, 2011 and recorded at Reception No. 2011006781 (collectively known as the "Prior Agreements");

WHEREAS, Operator has filed applications with the Colorado Oil and Gas Conservation Commission (the "COGCC") for drilling and spacing units, specifically COGCC docket numbers 170100469, 170700471, 170700470, 170900596, 170900598, 170900601, 170900602, 170900603, 170900605 (as may be amended, revised or supplemented, collectively the "Spacing Units") covering certain lands set forth therein (the "Spacing Areas");

WHEREAS, the Parties have negotiated new agreements in relation to the Operator's oil and gas development in the City (the "Project"), and are concurrently executing an Amended and Restated Oil and Gas Operator Agreement and a Surface Use Agreement;

WHEREAS, the City has agreed to (i) lease its unleased mineral interests owned by the City in the Spacing Units to Operator and (ii) assign the right to royalties for leased minerals owned by the City in the Spacing Units in exchange for Operator's agreement that additional wells not contemplated in the Amended and Restated Operator Agreement will not be drilled at the Livingston Pad; and

WHEREAS, the Parties desire the entry of this Settlement Agreement in order to assert mutual waivers and releases of potential claims from alleged breaches of Prior Agreements.

NOW, THEREFORE, the Parties, having carefully reviewed this matter and this Settlement Agreement, and having had sufficient time and opportunity to consult with legal counsel, and desiring to be legally bound hereby, agree as follows:

1. Terms. A term used in this Settlement Agreement shall have the same meaning as the term is used in the Amended and Restated Oil and Gas Operator Agreement and

the Surface Use Agreement, ("New Agreements") approved by resolution by the City Council at the same time as the Settlement Agreement.

2. Effective Date. This Settlement Agreement shall be effective on the same date that the New Agreements are effective upon approval by resolution of the City Council ("Effective Date"). In the event that the City Council does not approve one or more of the New Agreements then this Settlement Agreement is null and void and shall have no force and effect and the original Oil and Gas Operator Agreement dated August 23, 2013, as Supplemented and the Surface Use Agreement dated November 13, 2012, will remain in place.

3. The City Shall Not Object. As long as the Operator is in compliance with the New Agreements and any future Easement Grant and for purposes related to the Project, the City agrees that it will: (i) not object to, request a hearing on, or oppose any permits, applications, variances, waivers, or other related documents submitted by Operator to any local, state or federal agencies, including but not limited to, COGCC spacing applications covering the Spacing Areas (subject to the last two sentences of this paragraph), COGCC pooling applications or applications for permits to drill such as COGCC Form 2 and Form 2A: (ii) not object in any forum to any aspect or phase of the Project, including the number of wells planned at or the location of each Well Site; and (iii) provide such other written approvals, variances, and/or waivers as reasonably requested by Operator and consistent with the New Agreements. The Parties acknowledge that the City is currently protesting Operator's spacing and density applications related to the project, specifically COGCC docket numbers 170900596, 170900598, 170900601, 170900602, 170900603, 170900605, 171000749, and 171000752 (the "Protests"). The City agrees to withdraw the Protests so long as Operator's applications and proposed orders are consistent with the number of wells and locations described in the New Agreements.

4. The City and Operator Shall not Join or Intervene in Actions. The City and Operator shall not voluntarily join or intervene, without consent of the other, in any civil action in any court or quasi-judicial agency or body brought forth against Operator or City, respectively, with respect to the Project.

5. Operator's Well Sites and Mineral Interests Owned Shall Not Be Made a Part of Special Taxing Districts. To the extent not prohibited by law, the City and Operator agree that the City shall not take any affirmative action to approve, without Operator's written consent, (i) the inclusion any of the Well Sites or any of the minerals within the Spacing Units in any new or materially modified special districts or limited purpose governmental entities organized pursuant to the Colorado Special District Act, Article 1 of Title 32 of the Colorado Revised Statutes, or any other similar Colorado statutes or laws.

6. City Minerals. In exchange for Operator's agreement to limit the total number of future wells to be drilled within the City as set forth in the Amended and Restated Oil

and Gas Operator Agreement, the City agrees to (i) relinquish to the Operator its future interests in any royalties from wells drilled in the Spacing Units after the date hereof and (ii) execute one or more oil and gas leases to lease its unleased mineral interests within the Spacing Units to Operator, in the form attached as Annex A (the "Form Lease"). Additionally, Operator agrees to make offers to lease any unleased minerals within the Wildgrass subdivision using the Form Lease, but at a royalty rate of 17%. Additionally, Operator agrees to make offers to lease any unleased minerals within the Wildgrass subdivision using the Form Lease, but at a royalty rate of 17%. Operator will provide any unleased mineral holders within the Wildgrass subdivision with forced pooling notices and lease offers at least 60 days prior to any hearing on a forced pooling application.

7. Land Conveyance. As set forth in the Surface Use Agreement, Operator agreed to convey the surface of approximately thirty-nine (39) acres of property known as the Exchange Lands, subject to Operator's reservation of one or more easements for subsurface pipelines or access to existing lease roads. Operator agrees to remove all structures, debris, and personal property (as directed by City) on the Exchange Lands prior to transfer of the Exchange Lands and to execute an Open Space Trail Easement Agreement in favor of the City, in the form attached as Annex B.

8. Mutual General Release and Waiver of Claims. Operator and the City, in consideration of the promises and covenants contained in this Settlement Agreement and the Prior Agreements, the sufficiency of which is acknowledged by the Parties, do hereby forever, fully and unconditionally release, remise, acquit and discharge each other, and their respective affiliates and/or related companies, and their directors, officers, employees, contractors, agents, representatives, parents, subsidiaries, predecessors, and successors from any and all suits, actions, causes of action, demands, judgments, rights, claims, loss, damage, interest, attorney fees, costs and expenses and/or other relief of whatsoever kind or nature which each respective Party has from the beginning of time to the present (collectively, the "Claims") both presently known and unknown, arising out of or in connection with the terms of the Prior Agreements and any delays resulting from the City's request that Operator delay its project. This Settlement Agreement does not extend to nor preclude the pursuit of claims, suits, and causes of action and/or demands regarding the new plan of development contemplated in the New Agreements.

9. Fees, Costs, and Expenses. It is understood and agreed by the Parties hereto that each Party shall bear their own attorney fees, costs and expenses arising from or associated with this Settlement Agreement and with any breach or alleged breach of the Prior Agreements.

10. Choice of Law and Forum. This Settlement Agreement and the terms and conditions contained herein shall be governed by the laws of the State of Colorado. Any lawsuit to enforce the terms of this Settlement Agreement shall be brought in the City.

11. Binding on Successors and Assigns. This Settlement Agreement shall be binding upon and inure to the benefit of the parties and their respective successor and assigns.

12. Execution. This Settlement Agreement may be executed in counterparts each of which shall be deemed an original, and together of which shall constitute one and the same instrument. The Parties have had the opportunity to revise, comment upon and redraft this Agreement. Accordingly, it is agreed that no rule of construction shall apply against any party or in favor of any party. This Settlement Agreement shall be construed as if the Parties jointly prepared the Settlement Agreement and any uncertainty or ambiguity shall not be interpreted against any party and in favor of another party. If any clause or condition of this Agreement is found by a court of competent jurisdiction to be void or unenforceable, such finding shall not affect the validity and enforceability of the remainder of this Settlement Agreement.

13. Modification. This Agreement will not be amended, modified, revoked, supplemented, waived or otherwise changed except by a written instrument duly executed by the Parties and designated as such a change.

14. Headings. The headings of this Settlement Agreement are for reference and convenience only and shall not limit or otherwise affect the meaning or construction of the terms of this Agreement.

IN WITNESS WHEREOF, the Parties have caused this Settlement Agreement to be executed by a duly authorized representative on the day and year first written above.

THE CITY:

THE CITY AND COUNTY OF BROOMFIELD, COLORADO
A Colorado Municipal Corporation and County

Mayor

CITY & COUNTY OF BROOMFIELD SEAL COLORADO

ATTEST:

City & County Clerk

APPROVED AS TO FORM:

City & County Attorney

THE OPERATOR:

EXTRACTION OIL & GAS, INC.

Eric J. Christ, Vice President, General Counsel & Corporate Secretary

STATE OF COLORADO)
) ss
COUNTY OF Broomfield)

The foregoing instrument was acknowledged, subscribed and sworn to before me this 25TH day of October, 2017, by Eric J. Christ.

[SEAL]
LINDA J. VILLAREAL
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20134063200
My Commission Expires Oct. 7, 2021

Notary Public

My Commission Expires: October 7, 2021

ANNEX A

Oil and Gas Lease

PRODUCERS 88-PAID UP

OIL AND GAS LEASE

THIS AGREEMENT is made and entered into on the _____ day of _____ 2017, by **(Unleased Mineral Owner)** whose address is **(Unleased Mineral Owner Address)**, hereinafter called Lessor, (whether one or more), and **Extraction Oil & Gas, Inc.**, whose address is **370 17th Street, Suite 5300, Denver, CO 80202**, hereinafter called Lessee;

WITNESSETH, That the Lessor, for and in consideration of TEN AND MORE DOLLARS cash in hand paid, the receipt of which is hereby acknowledged, and the covenants and agreements hereinafter contained, has granted, demised, leased and let, and by these presents does grant, demise, lease and let exclusively unto the said Lessee, the land hereinafter described, with the exclusive right for the purpose of drilling, mining, exploring by geophysical and other methods, and operating for and producing therefrom oil and all gas of whatsoever nature or kind, specifically including helium, carbon dioxide, and coalbed methane and any and all substances produced in association therewith from coal-bearing formations, dewatering of coalbed methane, limited to all of the Codell and Niobrara formations, using methods and techniques which are not restricted to current technology, including the right to conduct exclusive geophysical and other exploratory tests; with the exclusive right to inject air, gas, water, brine and other fluids from any source into the subsurface strata, and any and all other rights and privileges necessary, incident to, or convenient for the economical operation of said land, alone or conjointly with contiguous land, and the injection of air, gas, water, brine, and other fluids into the subsurface strata, to produce, save and take care of said products, all upon that certain tract of land situated in the County of _____, State of **Colorado**, described as follows, to-wit:

Township Y, Range Z West of the 6th P.M.
Section: X

Containing **(Net Acres)** acres, more or less (the "Premises");

In addition to the lands described above, Lessor hereby grants, leases and lets exclusively unto Lessee, to the same extent as if specifically described, lands which are owned or claimed by Lessor by one of the following reasons: (1) all lands and rights acquired or retained by avulsion, accretion, reliction or otherwise as the result of a change in the boundaries or centerline of any river or stream traversing or adjoining the lands described above; (2) all riparian lands and rights which are or may be incident, appurtenant, related or attributed to Lessor in any lake, stream or river traversing or adjoining the lands described above by virtue of Lessor's ownership of the lands described above; (3) all lands included in any road, easement or right-of-way traversing or adjoining the lands described above which are or may be incident, appurtenant, related or attributed to Lessor by virtue of Lessor's ownership of the lands described above; and (4) all strips or tracts of land adjacent or contiguous to the lands described above owned or acquired by Lessor through adverse possession or other similar statutes of the state in which the lands are located.

1. It is agreed that this Lease shall remain in force for a primary term of three (3) years from this date and as long thereafter as oil or gas of whatsoever nature or kind is produced from the Premises or on acreage pooled, communitized or unitized therewith, or drilling operations are continued as hereinafter provided. If, at the expiration of the primary term of this Lease, oil or gas is not being produced on the Premises or on acreage pooled, communitized or unitized therewith but Lessee is then engaged in drilling, re-working, or dewatering operations thereon, then this Lease shall continue in force so long as such operations are being continuously prosecuted on the Premises or on acreage pooled, communitized or unitized therewith; and such operations shall be considered to be continuously prosecuted if not more than one hundred twenty (120) consecutive days shall elapse between the completion or abandonment of one well and the beginning of operations for the drilling of a subsequent well. If after discovery of oil or gas on said land or on acreage pooled, communitized or unitized therewith, the production thereof should cease from any cause after the primary term, this Lease shall not terminate if Lessee commences additional drilling, or re-working operations within one hundred twenty (120) days from the date of cessation of production, or from the date of completion of a dry hole. If oil or gas shall be discovered and produced as a result of such operations at or after the expiration of the primary term of this Lease, this Lease shall continue in force so long as oil or gas is produced from the Premises or on acreage pooled, communitized or unitized therewith. At any time during the Primary Term of this Lease, Lessee, at its option may make tender to Lessor payment in the amount of $500.00, thereby extending the Primary Term of this Lease by an additional two (2) years.

2. This is a PAID-UP LEASE. In consideration of the cash down payment, Lessor agrees that Lessee shall not be obligated, except as otherwise provided herein, to commence or continue any operations during the primary term. Lessee may at any time or times during or after the primary term surrender this Lease as to all or any portion of said land and as to any strata or stratum by delivering to Lessor or by filing for record a release or releases, and be relieved of all obligations thereafter accruing as to the acreage surrendered.

3. In consideration of the Premises, Lessee covenants and agrees:

1st. To deliver to the credit of Lessor, free of cost, in the pipeline to which Lessee may connect wells on the Premises, the equal ___% part of all oil produced and saved from the Premises.

2nd. To pay Lessor as royalty, on gas and the constituents thereof produced from the Premises and sold or used off the Premises or in the manufacture of products therefrom, the market value at the wellhead of __% of the product sold or used. All royalties paid on gas sold by Lessee or used off the Premises or used in the manufacture of products therefrom will be paid after deducting from such royalty Lessor's proportionate amount of all post-production costs, including but not limited to excise, production, and severance taxes, gathering and transportation costs from the wellhead to the point of sale, treating, compression, and processing costs. On product sold at the well, the royalty shall be __% of the net proceeds realized from such sale, after deducting from such royalty Lessor's proportionate amount of all of the above post-production costs and expenses, if any.

3rd. In calculating royalties on production hereunder, Lessee may deduct Lessor's proportionate part of any ad valorem, production and excise taxes, as well as other post-production costs, as described above.

4. If after the primary term one or more wells on the Premises or lands pooled, communitized, or unitized therewith, are capable of producing oil or gas or other substances covered hereby, but such well or wells are either shut in or production therefrom is not being sold by Lessee, such well or wells shall nevertheless be deemed to be producing for the purpose of maintaining this Lease. If for a period of ninety (90) consecutive days such well or wells are shut in or production therefrom is not sold by Lessee, including dewatering of coalbed gas, the Lessee shall pay an aggregate shut-in royalty of one dollar per acre then covered by this Lease, such payment to be made to Lessor on or before the anniversary date of this Lease next ensuing after the expiration of the said ninety (90) day period and thereafter on or before each anniversary of date of this Lease while the well or wells are shut in or production therefrom is not being sold by Lessee; provided that if this Lease is in its primary term or otherwise being maintained by operations, or if production is being sold by Lessee from another well on the Leased Premises or lands pooled, communitized or unitized therewith, no shut-in royalty shall be due until end of the next following anniversary date of this Lease that cessation of such operation or production occurs, as the case may be. Lessee's failure to properly pay shut-in royalty shall render Lessee liable for the amount due, but shall not operate to terminate this Lease.

5. If said Lessor owns a less interest in the Leased Premises than the entire and undivided fee simple estate therein, then the lands covered by this lease and the royalties (including any shut-in royalty) herein provided for shall be paid the Lessor only in the proportion which Lessor's interest bears to the whole and undivided fee.

6. Lessee shall have the right to use, free of cost, gas, oil, and water produced on the Leased Premises for Lessee's operation thereon.

7. The rights of Lessor and Lessee hereunder may be assigned in whole or part, by area or depth or zone and the rights and obligations of the parties hereunder shall extend to their respective heirs, devisees, executors, administrators, successors and assigns. No change in ownership of Lessor's interest (by assignment or otherwise) shall have the effect of reducing the rights or enlarging the obligations of Lessee hereunder, and no change in ownership shall be binding on Lessee until sixty (60) days after Lessee has been furnished with notice from Lessor and then only with respect to payments thereafter made. No other kind of notice, whether actual or constructive, shall be binding on Lessee. No present or future division of Lessor's ownership as to different portions or parcels of the Premises shall operate to enlarge the obligations or diminish the rights of Lessee, and all Lessee's operations may be conducted without regard to any such division. In the event of death of any person entitled to shut-in royalties hereunder, Lessee may pay or tender such shut-in royalties to the credit of the decedent or the decedent's estate. If at any time two or more persons are entitled to shut-in royalties hereunder, Lessee may pay or tender such shut-in royalties to such persons either jointly, or separately in proportion to the interest which each owns. If Lessee transfers a full or undivided interest in all or any portion of the Premises, the obligation to pay or tender shut-in royalties hereunder shall be divided between Lessee and transferee in proportion to the net acreage interest in this Lease then held by each. If Lessee transfers or assigns its interest hereunder in whole or in part, Lessee shall be relieved of all obligations thereafter arising with respect to the transferred interest, and failure of the transferee to satisfy such obligations with respect to the transferred interest shall not affect the rights of the Lessee with respect to any interest not so transferred. If all or any part of this Lease is assigned, no leasehold owner shall be liable for any act or omission of any other leasehold owner.

8. Lessee at its option to be exercised in good faith and as a reasonable prudent operator is hereby given the right and power at any time and from time to time as a recurring right, either before or after production, as to all or any part of the Premises and as to anyone or more of the formations hereunder to pool, communitize or unitize the leasehold estate and the mineral estate covered by this Lease with other contiguous land, lease or leases for the production of oil and gas, or separately for the production of either, when in Lessee's judgment it is necessary or advisable to do so, and irrespective of whether authority similar to this exists with respect to such other land, lease or leases. Likewise, units previously formed to include formations not producing oil or gas, may be reformed to exclude such non-producing formation. The forming or reforming of any unit, pooled area or communitized area shall be accomplished by Lessee executing and filing of record a declaration of such unitization, pooling or communitization or reformation, which declaration shall describe the unit, pooled area or communitized area. Any unit, pooled area, or communitized area may include land upon which a well has theretofore been completed or upon which operations for drilling have theretofore been commenced. Production, drilling, dewatering or reworking operations or a well shut in for want of a market anywhere on a unit, pooled area or communitized area which includes all or a part of this Lease shall be treated as if it were production, drilling, dewatering or reworking operations or a well shut in for want of a market under this Lease. In lieu of the royalties elsewhere herein specified, including shut-in gas royalties, Lessor shall receive on production from the unit, area or communitized area, royalties only on the portion of such production allocated to this Lease; such allocation shall be that

proportion of the unit, pooled area or communitized area production that the total number of surface acres covered by this Lease and included in the unit, pooled area, or communitized area bears to the total number of surface acres in such unit, pooled area, or communitized area. In addition to the foregoing, Lessee shall have the right to unitize, communitize, pool, or combine all or any part of the Leased Premises as to one or more of the formations hereunder with other lands in the same general area by entering into a cooperative or unit plan of development or operation approved by any governmental authority and, from time to time, with like approval, to modify, change or terminate any such plan or agreement and, in such event, the terms, conditions and provisions of this Lease shall be deemed modified to conform to the terms, conditions, and provisions of such approved cooperative or unit plan of development or operation and particularly, all drilling and development requirements of this Lease, express or implied, shall be satisfied by compliance with the drilling and development requirements of such plan or agreement, and this Lease shall not terminate or expire during the life of such plan or agreement. Lessor shall formally express Lessor's consent to any cooperative or unit plan of development or operation adopted by Lessee and approved by any governmental agency by executing the same upon request of Lessee.

9. For the same consideration recited above, Lessor hereby grants, assigns and conveys unto Lessee, its successors and assigns, a perpetual subsurface well bore easement under and through the leased premises for the placement of well bores (along routes selected by Lessee) from oil or gas wells the surface locations of which are situated on other tracts of land and which are not intended to develop the leased premises or lands pooled therewith and from which Lessor shall have no right to royalty or other benefit. Such subsurface well bore easements shall run with the land and survive any termination of this Lease.

10. Lessee's obligations under this Lease shall be governed by and subject to all applicable laws, rules, regulations and orders of any government authority having jurisdiction, including restrictions on the drilling and production of wells, and regulation of the price or transportation of oil, has or other substance covered hereby. This Lease shall not be terminated, in whole or in part, nor Lessee held liable in damages, for failure to comply therewith, if compliance is prevented by, or if such failure is the result of, any such law, order, rule or regulation.

11. When drilling, reworking, production or other operations or obligations under this Lease are prevented or delayed by laws, rules, regulations or orders, or by inability to obtain necessary permits, equipment, services material, water, electricity, fuel, access or easements, or by an act of God, strike, lockout, or other industrial disturbance, act of the public enemy, war, blockade, public riot, lightning, fire, storm, flood or other act of nature, explosion, fracking bans, governmental action, governmental delay, restraint or inaction, or by inability to obtain a satisfactory market for production in Lessee's opinion, or failure of purchasers or carriers to take or transport such production, or by any other cause, whether of the kind specifically enumerated above or otherwise, which is not reasonably within control of the Lessee, this Lease shall not terminate because of such prevention or delay and at Lessee's option, the period of such prevention or delay shall be added to the term hereof. Lessee shall not be liable for breach of any provision or implied covenants of this Lease when drilling, production, or other operations are so prevented or delayed.

12. No litigation shall be initiated by Lessor for damages, forfeiture or cancellation with respect to any breach or default by Lessee hereunder, for a period of at least 90 days after Lessor has given Lessee written notice fully describing the breach or default, and then only if Lessee fails to remedy the breach or default within such time period. In the event the matter is litigated and there is final judicial determination that a breach or default has occurred, this Lease shall not be forfeited or cancelled in whole or in part unless Lessee is given reasonable time after said judicial determination to remedy the breach or default and Lessee fails to do so.

13. In the event that this Lessor, during the primary term of this Lease, receives a bona fide offer which Lessor is willing to accept from any party offering to purchase from Lessor a lease covering any or all of the substances covered by this Lease and covering all or a portion of the land described herein, with the lease becoming effective upon expiration of this Lease, Lessor hereby agrees to notify Lessee in writing of said offer immediately, including in the notice the name and address of the offeror, the price offered, and all other pertinent terms and conditions of the offer. Lessee, for a period of fifteen days after receipt of the notice, shall have the prior and preferred right and option to purchase the lease or part thereof or interest therein, covered by the offer at the price and according to the terms and conditions specified in the offer.

14. Should any one or more of the parties hereinabove named as Lessor fail to execute this Lease, it shall nevertheless be binding upon all such parties who do execute it as Lessor. The word "Lessor," as used in this Lease shall mean any one or more or all of the parties who execute this Lease as Lessor. All the provisions of this Lease shall be binding on the heirs, successors and assigns of Lessor and Lessee.

15. Lessor hereby agrees that the Lessee shall have the right at any time to redeem for Lessor, by payment, any mortgages, taxes or other liens on the above described lands, in the event of default of payment by Lessor and be subrogated to the rights of the holder thereof, and the undersigned Lessors, for themselves and their heirs, successors and assigns, hereby surrender and release all right of dower and homestead in the premises described herein, insofar as said right of dower and homestead may in any way affect the purposes for which this Lease is made, as recited herein. If Lessee redeems any such lien, Lessee may recover any amount expended out of Lessor royalties or shut-in royalties.

IN WITNESS WHEREOF, this instrument is executed as of the date first above written.

(Unleased Mineral Owner) (Unleased Mineral Owner #2)

INDIVIDUAL ACKNOWLEDGMENT

STATE OF _____)
) SS:
COUNTY OF _____)

The foregoing instrument was acknowledged before me this _____ day of _____, 2017, by_____ , to me known to be the identical person(s) described herein, and who executed the within and foregoing instrument of writing and acknowledgment to me that he / she duly executed the same as his / her free and voluntary act and deed for the uses and purpose therein set forth.

WITNESS my hand and official seal.

My Commission Expires: _____

Signature/Notary Public: _____

Name/Notary Public (print): _____

Notary Public in and for the State of ___

STATE OF _____)
) SS:
COUNTY OF _____)

The foregoing instrument was acknowledged before me this _____ day of _____, 2017, by_____ , to me known to be the identical person(s) described herein, and who executed the within and foregoing instrument of writing and acknowledgment to me that he / she duly executed the same as his / her free and voluntary act and deed for the uses and purpose therein set forth.

WITNESS my hand and official seal.

My Commission Expires: _____

Signature/Notary Public: _____

Name/Notary Public (print): _____

Notary Public in and for the State of _____

ANNEX B

Open Space Trail Easement Agreement

OPEN SPACE TRAIL EASEMENT AGREEMENT

THIS OPEN SPACE TRAIL EASEMENT AGREEMENT (the "Agreement") is entered into as of _____, 2017, by and between_____, (hereafter referred to as "Owner") and the **CITY AND COUNTY OF BROOMFIELD,** a Colorado municipal corporation and county (hereafter referred to as the "City") acting through their authorized representatives, and provided that Owner and City may be individually referred to herein as a "Party" and together may be referred to as the "Parties."

RECITALS

A. Owner is the owner in fee simple of certain real property located in Broomfield, Colorado, as more particularly described as the Owner's Property on Exhibit A, attached to and made a part of this Agreement (hereinafter referred to as the "Property"); and

B. Owner has agreed to grant the City a perpetual, non-exclusive public easement for a community-use trail (the "Trail Easement") for the exclusive purpose of providing a public open space trail system. The route and course of the Trail Easement conveyed hereby are more particularly described on Exhibit B, attached to and made a part of this Agreement. The Parties understand and agree that the location of the Trail Easement depicted on Exhibit B may be adjusted as necessary by mutual written agreement of the Parties. Upon completion of the construction of the Trail, the City shall provide the Owner with a metes and bounds description prepared by a registered Land Surveyor depicting the Trail Easement. The width of the trails used upon the Trail Easement is __ feet wide, with an additional __ feet on both sides of those trails for a total width of __ feet, which shall thereafter constitute the final width and location of Trail Easement.

AGREEMENT

NOW, THEREFORE, in consideration of Ten Dollars ($10.00), the mutual covenants contained herein and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, Owner and the City agree as follows:

1. **Incorporation of Recital**. The Recitals set forth above are hereby incorporated into and made part of this Agreement.

2. **Grant of Easement for Trail**. Subject to the terms and conditions of this Agreement, Owner hereby grants to the City the Trail Easement for the exclusive purpose of providing an public open space trail system that shall include an __ feet wide width for the trails used upon the Trail Easement, with an additional __ feet on both sides of those trails for the exclusive purpose of operating and maintaining the trails used upon the Trail Easement, for a total width of __ feet. The route and course of the Trail Easement conveyed hereby are more particularly described on Exhibit B, attached hereto and made a part of this Agreement. Owner hereby agrees that the City's use of the Trail Easement may include grading, landscaping

consisting of re-seeding, work as determined appropriate by the City addressing issues associated with prairie dogs consistent with the City's adopted Prairie Dog Policy that may include relocation of the animals, and such other activities consistent with the City's use and maintenance of the Trail Easement as a public trail. Owner hereby agrees that the City may cross Owner's Property as depicted on Exhibit A and adjacent to the Trail Easement as necessary to provide for the City's use and maintenance of the Trail Easement as described herein, as long as such crossing does not interfere with the Owner's use and enjoyment of Owner's Property. Any use by the City of the Trail Easement shall be in compliance with all applicable governmental laws, codes, regulations, ordinances, and requirements. This Trail Easement shall continue so long as the Trail Easement is actively used for the limited purpose of use by any member of the public and incorporation into the City's public trail system.

3. **Consideration.** In consideration of this grant, Owner and the City agree the Trail Easement shall be subject to all of the terms and conditions set forth herein.

4. **Maintenance and Repair.** The City will have the sole responsibility of all Maintenance and Repair on the Trail Easement in accordance with the City's standard trail maintenance and repair procedures and in compliance with all applicable governmental codes, regulations, ordinances, and requirements.

5. **Liability.** To the extent permitted by law, each Party agrees to hold harmless the other Party, its officers, officials, employees, representatives, contractors, subcontractors, agents, affiliates, successors, assignees, and subsidiaries from and against any and all liability claims, demands and expenses, including court costs and attorneys' fees, resulting from any injury, loss, or damage arising out of or in any manner connected with the work, construction, or maintenance activities contemplated in this Agreement to be performed upon the Trail Easement caused in whole or in part by, or is claimed to be caused in whole or in part by the acts, errors, or omissions of the Party's officers, officials, employees, representatives, contractors, subcontractors, agents, affiliates, successors, assignees, and subsidiaries. To the extent permitted by law, City shall further indemnify and hold harmless Owner, its officers, employees, representatives, agents, affiliates, and subsidiaries from and against any and all liability claims, demands and expenses, including court costs and attorneys' fees, arising from any injury, loss, or damage arising out of any and all third-parties' use, occupancy, and activities upon the Trail Easement.

6. **Insurance**. The City shall be required to obtain and keep in full force and effect at all times during the term of this Agreement, and to pay the costs and premiums of, broad form general commercial liability insurance with respect to the use and operation of the Trail Easement, with the same limits as it would insure any public trail within the City's trail system.

7. **Interferences; Owner's Retained Rights**. The City will exercise all of the City's rights and obligations under this Agreement in such a manner as to avoid any disruption to the Owner's Property, as shown on Exhibit A, and to cause the least amount of unreasonable interference to the Owner. The Trail Easement is non-exclusive to the City, and Owner retains the right to the undisturbed use and occupancy of the Property (including the Trail Easement

Area) for any lawful purpose that does not impair any rights granted to City in this Agreement or the City's use of the Trail Easement as described herein.

8. **Severability**. The enforceability, invalidity or illegality of any provision of this Agreement shall not render the other provisions of this Agreement unenforceable, invalid or illegal, but rather the unenforceable, invalid or illegal provisions of this Agreement shall be deemed severed from this Agreement and this Agreement shall continue in full force and effect to the greatest extent permitted by applicable laws.

9. **Special Warranty.** Owner will warrant and forever defend the Trail Easement lands granted in this Agreement in the quiet and peaceable possession of City, its successors and assigns, against all and every person or persons claiming the whole or any part thereof by, through or under Owner.

10. **Notice**. All notices are required or permitted under this Agreement shall be given by overnight courier service, by registered or certified mail, postage prepaid, by facsimile, or by hand delivery, directed as follows:

If intended for the City:

City and County of Broomfield
Attn: City and County Manager
One DesCombes Drive
Broomfield, Co 80020
Phone: 303-438-6384
Fax: 303-438-6296

If intended for Owner:

Extraction Oil & Gas, Inc.
370 17th Street, Suite 5300
Denver, CO 80202
Attention: Land Department

11. **Default**. A Party shall be in default hereunder in the event that it fails to do, observe, keep and perform any of the terms, covenants, conditions, agreements or provisions hereunder within sixty (60) days after written notice by the other Party of said failure.

12. **Binding Effect**. This Agreement shall inure to the benefit of and be binding upon the parties hereto and their respective successors and assigns.

13. **Assignment.** The rights granted herein may be assigned in whole or in part, and the terms, conditions, and provisions of this Agreement are a covenant running with the land and shall extend to and be binding upon the successors, and assigns of Owner and City.

14. **Recordation**. This Agreement will be recorded in the Office of the Clerk and Recorder of Broomfield County, Colorado.

15. **No Oral Amendments or Modifications**. No amendments, waivers or modifications hereof shall be made or deeded to have been made unless in writing and executed by the party to be bound thereby.

16. **Other**. This Agreement may be executed in one or more counterparts, each of which shall be deemed an original, and all of which together shall constitute one and the same agreement. This Agreement shall not be binding upon any Party hereto unless and until the Parties have executed this Agreement. Time is of the essence. This Agreement represents the entire agreement between the parties and no additional or different oral representation, promise, or agreement shall be binding on any of the parties hereto with respect to the subject matter of this instrument, unless stated in writing signed by Owner and the City. Failure of any party hereto to insist upon the strict performance of any provision of this Agreement shall not be construed as a waiver for the future of any such provision. This Agreement is intended to describe the rights and responsibilities only as to the Parties hereto. This Agreement is not intended and shall not be deemed to confer any rights on any person or entity not named as a party hereto.

17. **Governmental Immunity Act**. Notwithstanding anything to the contrary herein, the City shall not be deemed to have waived in any manner the rights, obligations, and protections afforded to, or imposed on the City by law including without limitation, the Colorado Governmental Immunity Act or the Colorado Constitution.

IN WITNESS WHEREOF, Owner and the City have executed this Agreement as of the date first written above.

CITY:
CITY AND COUNTY OF BROOMFIELD, a Colorado Municipal Corporation & County

_____
City & County Manager

ATTEST:

_____
City & County Clerk

APPROVED AS TO FORM:

_____
City & County Attorney

OWNER:

_____

By: Matthew R. Owens
Title: President

STATE OF COLORADO)
) ss
COUNTY OF _____)

The foregoing instrument was acknowledged, subscribed and sworn to before me this ____ day of _____, 2017, by _____.

[SEAL]

_____

Notary Public

My Commission Expires: _____

EXHIBIT U

FULLY REDACTED

EXHIBIT V

FULLY REDACTED

EXHIBIT W

FULLY REDACTED

EXHIBIT X

FULLY REDACTED

EXHIBIT Y

Contact:
Rogan McGillis
Chief Financial Officer
rogan.mcgillis@arbmidstream.com
+1 (720) 600-7500

ARB Midstream Secures Large Production Dedication in Colorado's Niobrara Play and Announces Plans to Expand the Crude Gathering System

Denver, CO, July 13, 2017 - **Platte River Midstream, LLC** ("PRM"), a subsidiary of **ARB Midstream, LLC** ("ARB"), today announced it has secured a long-term, fee-based crude oil transportation services agreement with one of the largest acreage holders and oil producers in the DJ Basin ("the Company"). The Company has dedicated production from existing and all future wells drilled in a 9-township area in and around the Berthoud, Windsor and Greeley areas of Weld County, Colorado. The crude oil production will be gathered by pipeline into PRM's Lucerne West facility.

"This agreement creates a premier midstream platform for ARB Midstream in the DJ basin with a significant amount of dedicated production under long-term gathering agreements. The Company is one of the DJ's largest and most successful producers in the DJ Basin," stated Adam Bedard, Chief Executive Officer at ARB Midstream, "and they will provide significant growth in throughput for PRM's gathering system."

Platte River's gathering system, which has a capacity of 157,000 b/d and serves multiple producers, started service in mid-2016. The system gathers crude oil from the inner core of the DJ Basin, and delivers it to long haul pipelines for delivery into to downstream markets including direct access to the market center at Cushing, Oklahoma. The system also includes storage tanks and truck stations to maximize shipping and delivery options.

"With over 100-miles of pipeline in the ground by the end of this year, the Platte River Gathering System serves two primary objectives – to provide safe, reliable pipeline take away capacity to support the Company's rapid crude oil growth in the DJ Basin and to improve wellhead economics through stronger price realizations. Gathering crude oil by pipeline also meets the Company's goal of significantly reducing truck traffic from their production facilities. The Agreement with PRM secures these objectives for the Company for the long term," remarked Pat McMurry, ARB's Senior Vice President of Gathering and Logistics.

About ARB Midstream, LLC

ARB Midstream, LLC is a privately held company, based in Denver, CO, that provides complete midstream and marketing solutions for crude oil, LPGs and refined products. ARB markets crude oil and operates assets in Colorado, Texas, Wyoming, North Dakota, and Calgary, AB.

ARB was formed with a strategic financing relationship with BV Natural Resources, LLC, the energy division of Ball Ventures, LLC. Ball Ventures, LLC is a private company headquartered in Idaho Falls, Idaho, founded by Allen Ball, an Idaho businessman and entrepreneur that has helped build several successful companies, some of which operate in markets around the world. Under the leadership of CEO Cortney Liddiard, Ball Ventures, LLC has expanded its portfolio of real estate and private equity investments, in addition to the energy division of the company.

For more information about ARB Midstream, visit www.arbmidstream.com

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EXHIBIT Z

FULLY REDACTED

EXHIBIT AA

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2020

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from _____ to _____

Commission file number 001-37907



EXTRACTION OIL & GAS, INC.

(Exact name of registrant as specified in its charter)

Delaware	**46-1473923**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
370 17th Street **Suite 5300** **Denver, Colorado**	**80202**
(Address of principal executive offices)	

(720) 557-8300

(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of exchange on which registered
Common Stock, par value $0.01	**XOG**	**NASDAQ Global Select Market**

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer", "accelerated filer", "smaller

reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer	☐	Accelerated Filer	☒
Non-Accelerated Filer	☐	Smaller Reporting Company	☐
		Emerging Growth Company	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The total number of shares of common stock, par value $0.01 per share, outstanding as of May 8, 2020 was 138,135,046.

EXTRACTION OIL & GAS, INC.
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PART I. FINANCIAL INFORMATION

ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

EXTRACTION OIL & GAS, INC.
CONDENSED CONSOLIDATED BALANCE SHEETS
(In thousands, except share data)
(Unaudited)

	March 31, 2020	December 31, 2019
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 31,993	$ 32,382
Accounts receivable		
Trade	49,878	32,009
Oil, natural gas and NGL sales	38,850	105,103
Inventory, prepaid expenses and other	34,494	36,702
Commodity derivative asset	164,330	17,554
Total Current Assets	319,545	223,750
Property and Equipment (successful efforts method), at cost:		
Proved oil and gas properties	4,676,967	4,530,934
Unproved oil and gas properties	417,021	524,214
Wells in progress	154,981	149,733
Less: accumulated depletion, depreciation, amortization and impairment charges	(3,057,098)	(2,985,983)
Net oil and gas properties	2,191,871	2,218,898
Gathering systems and facilities, net of accumulated depreciation	—	315,777
Other property and equipment, net of accumulated depreciation	72,589	72,542
Net Property and Equipment	2,264,460	2,607,217
Non-Current Assets:		
Commodity derivative asset	88,783	13,229
Other non-current assets	30,600	82,761
Total Non-Current Assets	119,383	95,990
Total Assets	$ 2,703,388	$ 2,926,957
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 163,057	$ 190,864
Accounts payable and accrued liabilities, related party	46,777	—
Revenue payable	104,702	108,493
Production taxes payable	115,556	115,489
Commodity derivative liability	716	1,998
Accrued interest payable	18,042	20,625
Asset retirement obligations	15,328	27,058
Total Current Liabilities	464,178	464,527
Non-Current Liabilities:		
Credit facility	470,000	470,000
Senior Notes, net of unamortized debt issuance costs	1,086,347	1,085,777
Production taxes payable	119,675	98,740
Commodity derivative liability	—	108
Other non-current liabilities	59,689	54,579
Asset retirement obligations	78,445	68,850
Deferred tax liability	2,200	—
Total Non-Current Liabilities	1,816,356	1,778,054
Total Liabilities	2,280,534	2,242,581
Commitments and Contingencies—Note 13		
Series A Convertible Preferred Stock, $0.01 par value; 50,000,000 shares authorized, 185,280 issued and outstanding	182,157	175,639
Stockholders' Equity:		
Common stock, $0.01 par value; 900,000,000 share authorized; 137,891,740 and 137,657,922 issued and outstanding, respectively	1,336	1,336
Treasury stock, at cost, 38,859,078 shares	(170,138)	(170,138)
Additional paid-in capital	2,143,670	2,156,383
Accumulated deficit	(1,734,171)	(1,743,208)
Total Extraction Oil & Gas, Inc. Stockholders' Equity	240,697	244,373
Noncontrolling interest	—	264,364
Total Stockholders' Equity	240,697	508,737
Total Liabilities and Stockholders' Equity	$ 2,703,388	$ 2,926,957

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART OF
THESE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

EXTRACTION OIL & GAS, INC.
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share data)
(Unaudited)

	For the Three Months Ended March 31,	
	2020	**2019**
Revenues:		
Oil sales	$ 124,219	$ 165,424
Natural gas sales	22,302	35,892
NGL sales	17,193	20,601
Gathering and compression	1,473	—
Total Revenues	165,187	221,917
Operating Expenses:		
Lease operating expense	30,390	21,857
Midstream operating expenses	3,935	—
Transportation and gathering	22,786	10,365
Production taxes	13,454	18,129
Exploration and abandonment expenses	112,480	6,194
Depletion, depreciation, amortization and accretion	76,051	118,770
Impairment of long lived assets	775	8,248
Gain on sale of property and equipment	—	(222)
General and administrative expense	10,596	27,652
Other operating expenses	52,575	—
Total Operating Expenses	323,042	210,993
Operating Income (Loss)	(157,855)	10,924
Other Income (Expense):		
Commodity derivative gain (loss)	263,015	(122,091)
Loss on deconsolidation of Elevation Midstream, LLC	(73,139)	—
Interest expense	(21,358)	(13,008)
Other income	574	1,143
Total Other Income (Expense)	169,092	(133,956)
Income (Loss) Before Income Taxes	11,237	(123,032)
Income tax (expense) benefit	(2,200)	29,000
Net Income (Loss)	$ 9,037	$ (94,032)
Net income attributable to noncontrolling interest	6,160	3,975
Net Income (Loss) Attributable to Extraction Oil & Gas, Inc.	2,877	(98,007)
Adjustments to reflect Series A Preferred Stock dividends and accretion of discount	(6,518)	(4,317)
Net Loss Available to Common Shareholders, Basic and Diluted	$ (3,641)	$ (102,324)
Loss Per Common Share (Note 12)		
Basic and diluted	$ (0.03)	$ (0.60)
Weighted Average Common Shares Outstanding		
Basic and diluted	137,726	170,702

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART OF
THESE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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EXTRACTION OIL & GAS, INC.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)
(Unaudited)

	For the Three Months Ended March 31,	
	2020	2019
Cash flows from operating activities:		
Net income (loss)	$ 9,037	$ (94,032)
Reconciliation of net income (loss) to net cash provided by operating activities:		
Depletion, depreciation, amortization and accretion	76,051	118,770
Abandonment and impairment of unproved properties	106,928	3,893
Impairment of long lived assets	775	8,248
Gain on sale of property and equipment	—	(222)
Gain on repurchase of 2026 Senior Notes	—	(7,317)
Amortization of debt issuance costs	1,242	1,498
Non-cash lease expense	4,871	2,486
Contract asset	8,465	—
Commodity derivatives (gain) loss	(263,015)	122,091
Settlements on commodity derivatives	24,932	(3,538)
Earnings in unconsolidated subsidiaries	(480)	(338)
Loss on deconsolidation of Elevation Midstream, LLC	73,139	—
Distributions from unconsolidated subsidiaries	—	1,751
Deferred income tax expense (benefit)	2,200	(29,000)
Stock-based compensation	—	13,008
Changes in current assets and liabilities:		
Accounts receivable—trade	(9,127)	11,908
Accounts receivable—oil, natural gas and NGL sales	66,253	2,981
Inventory, prepaid expenses and other	584	136
Accounts payable and accrued liabilities	(7,699)	(10,638)
Accounts payable and accrued liabilities, related party	46,777	—
Revenue payable	(1,690)	(21,506)
Production taxes payable	21,002	22,919
Accrued interest payable	(2,583)	(4,429)
Asset retirement expenditures	(10,563)	(4,558)
Net cash provided by operating activities	147,099	134,111
Cash flows from investing activities:		
Oil and gas property additions	(143,000)	(188,027)
Sale of property and equipment	12,117	16,521
Gathering systems and facilities additions, net of cost reimbursements	4,193	(49,175)
Other property and equipment additions	(2,980)	(8,213)
Investment in unconsolidated subsidiaries	(10,033)	(4,929)
Distributions from unconsolidated subsidiary, return of capital	—	1,448
Net cash used in investing activities	(139,703)	(232,375)
Cash flows from financing activities:		
Borrowings under credit facility	70,000	65,000
Repayments under credit facility	(70,000)	(25,000)
Repurchase of 2026 Senior Notes	—	(28,460)
Repurchase of common stock	—	(32,212)
Payment of employee payroll withholding taxes	(35)	(454)
Dividends on Series A Preferred Stock	—	(2,721)
Debt and equity issuance costs	(22)	(94)
Preferred Unit issuance costs	—	(10)
Net cash used in financing activities	(57)	(23,951)
Effect of deconsolidation of Elevation Midstream, LLC	(7,728)	—
Decrease in cash and cash equivalents	(389)	(122,215)
Cash, cash equivalents at beginning of period	32,382	234,986
Cash, cash equivalents at end of the period	$ 31,993	$ 112,771
Supplemental cash flow information:		
Property and equipment included in accounts payable and accrued liabilities	$ 99,602	$ 143,168
Cash paid for interest	$ 24,865	$ 25,265
Accretion of beneficial conversion feature of Series A Preferred Stock	$ 1,770	$ 1,596
Preferred Units commitment fees and dividends paid-in-kind	$ 6,160	$ 3,975
Series A Preferred Stock dividends paid-in-kind	$ 4,748	$ —

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART OF
THESE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

EXTRACTION OIL & GAS, INC.
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY AND NONCONTROLLING INTEREST
(In thousands)
(Unaudited)

	Common Stock		Treasury Stock		Additional Paid in Capital	Accumulated Deficit	Extraction Oil & Gas, Inc. Stockholders' Equity	Noncontrolling Interest	Total Stockholders' Equity
	Shares	Amount	Shares	Amount				Amount	
Balance at January 1, 2020	176,517	$ 1,336	38,859	$ (170,138)	$ 2,156,383	$ (1,743,208)	$ 244,373	$ 264,364	$ 508,737
Preferred Units commitment fees & dividends paid-in-kind	—	—	—	—	(6,160)	—	(6,160)	6,160	—
Series A Preferred Stock dividends	—	—	—	—	(4,748)	—	(4,748)	—	(4,748)
Accretion of beneficial conversion feature on Series A Preferred Stock	—	—	—	—	(1,770)	—	(1,770)	—	(1,770)
Restricted stock issued, net of tax withholdings and other	234	—	—	—	(35)	—	(35)	—	(35)
Net income	—	—	—	—	—	9,037	9,037	—	9,037
Effects of deconsolidation of Elevation Midstream, LLC	—	—	—	—	—	—	—	(270,524)	(270,524)
Balance at March 31, 2020	176,751	$ 1,336	38,859	$ (170,138)	$ 2,143,670	$ (1,734,171)	$ 240,697	$ —	$ 240,697

	Common Stock		Treasury Stock		Additional Paid in Capital	Accumulated Deficit	Extraction Oil & Gas, Inc. Stockholders' Equity	Noncontrolling Interest	Total Stockholders' Equity
	Shares	Amount	Shares	Amount				Amount	
Balance at January 1, 2019	176,210	$ 1,678	4,543	$ (32,737)	$ 2,153,661	$ (375,788)	$ 1,746,814	$ 147,872	$ 1,894,686
Preferred Units issuance costs	—	—	—	—	—	—	—	(10)	(10)
Preferred Units commitment fees & dividends paid-in-kind	—	—	—	—	(3,975)	—	(3,975)	3,975	—
Stock-based compensation	—	—	—	—	13,008	—	13,008	—	13,008
Series A Preferred Stock dividends	—	—	—	—	(2,721)	—	(2,721)	—	(2,721)
Accretion of beneficial conversion feature on Series A Preferred Stock	—	—	—	—	(1,596)	—	(1,596)	—	(1,596)
Repurchase of common stock	—	(77)	7,824	(32,135)	—	—	(32,212)	—	(32,212)
Restricted stock issued, net of tax withholdings	270	—	—	—	(454)	—	(454)	—	(454)
Net loss	—	—	—	—	—	(94,032)	(94,032)	—	(94,032)
Balance at March 31, 2019	176,480	$ 1,601	12,367	$ (64,872)	$ 2,157,923	$ (469,820)	$ 1,624,832	$ 151,837	$ 1,776,669

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART OF
THESE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

EXTRACTION OIL & GAS, INC.
NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Note 1—Business and Organization

Extraction Oil & Gas, Inc. (the "Company" or "Extraction") is an independent oil and gas company focused on the acquisition, development and production of oil, natural gas and natural gas liquids (“NGLs”) reserves in the Rocky Mountain region, primarily in the Wattenberg Field of the Denver-Julesburg Basin (the "DJ Basin") of Colorado, as well as the construction and support of midstream assets to gather and process crude oil and gas production. Extraction is a public company listed for trading on the NASDAQ Global Select Market under the symbol "XOG."

Deconsolidation of Elevation Midstream, LLC

Elevation Midstream, LLC ("Elevation"), a Delaware limited liability company, is focused on the construction and operation of gathering systems and facilities to serve the development of acreage in the Company’s Hawkeye and Southwest Wattenberg areas. Midstream assets of Elevation are represented as the gathering systems and facilities line item within the condensed consolidated balance sheets.

During the first quarter of 2020, Elevation's non-controlling interest owner, which owns 100% of Elevation's preferred stock, per contractual agreement, expanded Elevation's then five member board of managers by four seats and filled them with managers of their choosing (the "Board Expansion"). Because Extraction had the right to appoint only three of the managers of Elevation before and after Board Expansion, Extraction determined the Company had lost voting control of Elevation, and on March 16, 2020 deconsolidated Elevation and began accounting for the entity as an equity method investment. Though Extraction determined control of Elevation was lost under the voting interest model of consolidation, the Company also determined significant influence was not lost due to (1) Extraction owning 100% of the common stock, (2) Extraction appointing three of the nine managers of Elevation and (3) Extraction's continuing involvement in the day-to-day operation of Elevation through a management services agreement. Because Extraction also determined the Company is not the primary beneficiary, Elevation Midstream, LLC is not a variable interest entity.

Extraction elected the fair value option to remeasure the Elevation equity method investment and determined it had no fair value. The Company recorded a $73.1 million loss on deconsolidation of the investment in the condensed consolidated statements of operations for the three months ended March 31, 2020. Also, as of March 31, 2020, Elevation determined certain gathering systems and facilities were impaired by $50.3 million as a result of the abandonment of certain projects. In accordance with Accounting Standards Codification *Topic 323-10-35-20: Investments—equity method and joint ventures*, Extraction discontinued applying the equity method investment for Elevation as the impairment charge would have reduced the investment below zero.

On May 1, 2020, Elevation's board of managers issued 1,530,000,000 common units at a price of $0.01 per unit to certain of Elevation's members other than Extraction (the "Capital Raise"). The Capital Raise caused Extraction's ownership of Elevation to be diluted to less than 0.01%. As a result of the Capital Raise, beginning in May 2020 Extraction will account for Elevation under the cost method of accounting. The Company reserves all rights related to actions taken by Elevation’s board of managers.

Note 2—Basis of Presentation, Significant Accounting Policies and Recent Accounting Pronouncements

Basis of Presentation

The unaudited condensed consolidated financial statements include the accounts of the Company, including its wholly owned subsidiaries. All significant intercompany balances and transactions have been eliminated in consolidation. The financial statements included herein were prepared from the records of the Company in accordance with generally accepted accounting principles in the United States (“GAAP”) and the Securities and Exchange Commission rules and regulation for interim financial reporting. In the opinion of management, all adjustments, consisting primarily of normal recurring accruals that are considered necessary for a fair statement of the unaudited condensed consolidated financial information, have been included. However, operating results for the period presented are not necessarily indicative of the results that may be expected for a full year. Interim condensed consolidated financial

statements and the year-end balance sheets do not include all of the information and notes required by GAAP for audited annual consolidated financial statements. These unaudited condensed consolidated financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes included in the Company's Annual Report on Form 10-K for the year ended December 31, 2019 ("Annual Report").

Significant Accounting Policies

The significant accounting policies followed by the Company are set forth in Note 2 to the Company's consolidated financial statements in its Annual Report and are supplemented by the notes to the unaudited condensed consolidated financial statements in this report. These unaudited condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes included in the Company's Annual Report.

Revenue — Contract Balances

The Company has a certain revenue contract with an initial term beginning on November 1, 2016 and continuing until October 31, 2020 after which the contract begins an automatic month-to-month renewal unless terminated by either party giving notice at least 180 days prior to the effective termination date but in no event can either party give such notice earlier than November 1, 2020. Based on the accounting treatment pursuant to ASC 606 - Revenue from Contracts with Customers, the contract term ends on April 30, 2021 because it may be terminated by either party with no penalty effective as of such date. The contract term impacts the amount of consideration that can be included in the transaction price. Generally, under the Company's various sales contracts, the Company invoices customers once its performance obligations have been satisfied, at which point payment is unconditional. For the three months ended March 31, 2020, the Company allocated $8.5 million to a satisfied performance obligation recognized within oil sales under ASC 606. As of March 31, 2020, the Company estimated a performance obligation under ASC 606 of $46.2 million, of which $3.9 million is recorded in accounts payable and accrued liabilities and $42.3 million is recorded in other non-current liabilities. A corresponding asset was recorded in the amount of $13.0 million, of which $12.1 million is recorded in inventory, prepaid expenses and other and $0.9 million is recorded in other non-current assets. The asset will be amortized into revenue over the contractual term of the contract, and the liability will be relieved if a deficiency payment is made to the counterparty or when the Company's minimum volume commitments are fulfilled.

Other Operating Expenses

Other operating expenses were $52.6 million for the three months ended March 31, 2020. This amount is primarily made up of a $46.8 million loss contingency from an alleged breach in contract stemming from a purported failure to complete the pipeline extensions connecting certain wells to the Badger central gathering facility prior to April 1, 2020. Please see *Note 13—Commitments and Contingencies* for further details. Also included in this amount is a $5.8 million charge to income for expenses related to a workforce reduction in February 2020.

Impairment of Oil and Gas Properties

The Company identified an impairment triggering event for its proved oil and gas properties as of March 31, 2020 due to the significant decrease in oil and gas prices during the first quarter of 2020. As such, the Company performed a quantitative assessment as of March 31, 2020, and proved property in its northern field was impaired. For the three months ended March 31, 2020 and 2019, the Company recognized $0.8 million and $8.2 million, respectively, in impairment expense on its proved oil and gas properties related to impairment of assets in its northern field. The fair value did not exceed the Company's carrying amount associated with its proved oil and gas properties in its northern field. The Company did not have any proved property impairment in its Core DJ Basin field, primarily because of the $1.3 billion impairment charge that was recorded in the fourth quarter of 2019.

Of the Company's $112.5 million in exploration and abandonment expenses for the three months ended March 31, 2020, $106.9 million was lease abandonment expense. Unproved oil and gas properties consist of costs to acquire unevaluated leases as well as costs to acquire unproved reserves. The Company evaluates significant unproved oil and gas properties for impairment based on remaining lease term, drilling results, reservoir performance, seismic interpretation or future plans to develop acreage. When successful wells are drilled on undeveloped leaseholds, unproved property costs are reclassified to proved properties and depleted on a unit-of-production basis. Impairment expense and

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lease extension payments for unproved properties is reported in exploration and abandonment expenses in the condensed consolidated statements of operations.

Recent Accounting Pronouncements

In June 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-13, Financial Instruments—Credit Losses. In May 2019, ASU No. 2016-13 was subsequently amended by ASU No. 2019-04, Codification Improvements to Topic 326, Financial Instruments—Credit Losses and ASU No. 2019-05, Financial Instruments—Credit Losses (Topic 326): Targeted Transition Relief. ASU No. 2016-13, as amended, affects trade receivables, financial assets and certain other instruments that are not measured at fair value through net income. This ASU replaced the incurred loss approach with an expected loss model for instruments measured at amortized cost and was effective for financial statements issued for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. ASU No. 2016-13 will be applied using a modified retrospective approach through a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. The Company adopted this ASU on January 1, 2020, and the adoption did not have a material impact on the consolidated financial statements and related disclosures.

In August 2018, the FASB issued ASU No. 2018-13, which removes or modifies current fair value disclosures and adds additional disclosures. The update to the guidance is the result of the FASB's test of the principles developed in its disclosure effectiveness project, which is designed to improve the effectiveness of disclosures in the notes to the financial statements. The disclosures that have been removed or modified may be applied immediately with retrospective application. For public entities, the new guidance was effective for fiscal years beginning after December 15, 2019, including interim reporting periods within that reporting period. The Company adopted this ASU on January 1, 2020, and the adoption did not have a material impact on the consolidated financial statements and related disclosures.

In August 2018, the FASB issued ASU No. 2018-15, which aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software and hosting arrangements that include an internal-use software license. For public entities, the guidance is effective for fiscal years beginning after December 15, 2019, including interim reporting periods within that reporting period. The Company adopted this ASU on January 1, 2020 which did not have a material impact on the consolidated financial statements and related disclosures as capitalized costs for internal-use software were not material as of March 31, 2020.

Other than as disclosed above or in the Company’s Annual Report, there are no other accounting standards applicable to the Company as of March 31, 2020 and through the date of this filing that would have a material effect on the Company’s unaudited condensed consolidated financial statements and related disclosures that have been issued but not yet adopted by the Company.

Note 3—Divestitures

February 2020 Divestiture

In February 2020, the Company completed the sale of certain non-operated producing properties for aggregate sales proceeds of approximately $12.2 million, subject to customary purchase price adjustments. No gain or loss was recognized for the February 2020 Divestiture. The Company continues to explore divestitures as part of our ongoing initiative to divest non-strategic assets.

December 2019 Divestiture

In December 2019, the Company completed the sale of certain non-operated producing properties for aggregate sales proceeds of approximately $10.0 million, subject to customary purchase price adjustments. No gain or loss was recognized for the December 2019 Divestiture.

August 2019 Divestiture

In August 2019, the Company completed the sale of certain non-operated producing properties for aggregate sales proceeds of approximately $22.0 million, subject to customary purchase price adjustments. No gain or loss was recognized for the August 2019 Divestiture.

March 2019 Divestiture

In March 2019, the Company completed the sale of its interests in approximately 5,000 net acres of leasehold and producing properties for aggregate sales proceeds of approximately $22.4 million. The effective date for the March 2019 Divestiture was July 1, 2018 with purchase price adjustments calculated as of the closing date of $5.9 million, resulting in net proceeds of $16.5 million. No gain or loss was recognized for the March 2019 Divestiture.

Note 4—Going Concern

The Company depends on cash flows from operating activities and, as necessary and available, borrowings under its senior secured revolving credit facility (the "revolving credit facility") to fund its capital expenditures and working capital requirements. Additionally, the Company historically has used proceeds from the issuance of equity and debt securities in the capital markets and from sales or other monetizations of assets to fund its capital expenditures and working capital requirements.

The market price for oil, natural gas and NGLs decreased significantly beginning in the first quarter of 2020, continuing into the second quarter of 2020. The decrease in the market price for the Company's production directly reduces the Company's cash flow from operations and indirectly impacts its other potential sources of funds described above. The Company has reduced its 2020 upstream capital budget and as a result expects to suspend drilling in the second half of 2020 and does not see production returning to historical levels for the foreseeable future. As discussed in *Note 5—Long-Term Debt*, lenders under the revolving credit facility elected to reduce the borrowing base and elected commitments to $650.0 million from $950.0 million on April 27, 2020, and the Company borrowed all of its remaining available capacity under the revolving credit facility. As a result of the reduction of the borrowing base and elected commitments, it is probable that the Company will not meet the financial covenants under the revolving credit facility for the three months ended June 30, 2020 when assuming the Company's current financial forecast.

If the Company does not obtain a waiver of its financial covenants for the three months ended June 30, 2020, the lenders under the revolving credit facility will be able to accelerate maturity of the debt. Any acceleration of the obligations under the revolving credit facility would result in a cross-default and potential acceleration of the maturity of the Company's other outstanding long-term debt amounting to approximately $1.1 billion. These defaults create uncertainty associated with the Company's ability to repay its outstanding long-term debt obligations as they become due and creates a substantial doubt over the Company's ability to continue as a going concern.

As a result of the impacts to the Company's financial position resulting from declining commodity price conditions and in consideration of the substantial amount of long-term debt and preferred stock outstanding, the Company has engaged advisors to assist with the evaluation of strategic alternatives, which may include, but not be limited to, seeking a restructuring, amendment or refinancing of existing debt through a private restructuring or reorganization under Chapter 11 of the Bankruptcy Code. However, there can be no assurances that the Company will be able to successfully restructure its indebtedness, improve its financial position or complete any strategic transactions. As a result of these uncertainties and the likelihood of a restructuring or reorganization, management has concluded that there is substantial doubt regarding the Company's ability to continue as a going concern.

The consolidated financial statements have been prepared on a going concern basis of accounting, which contemplates continuity of operations, realization of assets and satisfaction of liabilities and commitments in the normal course of business. The consolidated financial statements do not reflect any adjustments that might result if the Company is unable to continue as a going concern.

Note 5—Long-Term Debt

The Company's long-term debt consisted of the following (in thousands):

	March 31, 2020	December 31, 2019
Credit facility due August 16, 2022 (or an earlier time as set forth in the credit facility)	$ 470,000	$ 470,000
2024 Senior Notes due May 15, 2024	400,000	400,000
2026 Senior Notes due February 1, 2026	700,189	700,189
Unamortized debt issuance costs on Senior Notes	(13,842)	(14,412)
Total long-term debt	1,556,347	1,555,777
Less: current portion of long-term debt	—	—
Total long-term debt, net of current portion	$ 1,556,347	$ 1,555,777

Credit Facility

In August 2017, the Company entered into an amendment and restatement of its existing credit facility (prior to amendment and restatement, the "Prior Credit Facility"), to provide aggregate commitments of $1.5 billion with a syndicate of banks, which is subject to a borrowing base. The credit facility matures on the earlier of (a) August 16, 2022, (b) April 15, 2021, if (and only if) (i) the Series A Preferred Stock have not been converted into common equity or redeemed prior to April 15, 2021 (the Company can redeem the Series A Preferred Stock at any time), and (ii) prior to April 15, 2021, the maturity date of the Series A Preferred Stock has not been extended to a date that is no earlier than six months after August 16, 2022 or (c) the earlier termination in whole of the commitments under the credit facility. No principal payments are generally required until the credit agreement matures or in the event that the borrowing base falls below the outstanding balance.

As of March 31, 2020, the credit facility had a maximum credit amount of $1.5 billion, subject to a borrowing base and elected commitments of $950.0 million. As of March 31, 2020 and December 31, 2019, the Company had outstanding borrowings of $470.0 million and had standby letters of credit of $49.5 million which reduces the availability of the undrawn borrowing base. At March 31, 2020, the undrawn balance under the credit facility was $480.0 million before letters of credit. The amount available to be borrowed under the Company's revolving credit facility is subject to a borrowing base that is redetermined semiannually on each May 1 and November 1, and will depend on the volumes of the Company's proved oil and gas reserves, commodity prices, estimated cash flows from these reserves and other information deemed relevant by the administrative agent under the Company's revolving credit facility. Additionally, the undrawn balance may be constrained by the Company's quantitative covenants under the credit facility, including the current ratio and ratio of consolidated debt less cash balances to its consolidated EBITDAX, at the next required quarterly compliance date.

On April 27, 2020, the lenders under our revolving credit facility provided notice to the Company that they had completed the redetermination scheduled to occur on May 1, 2020, and via this redetermination, our borrowing base had been reduced from $950.0 million to $650.0 million. As of May 11, 2020, following this redetermination, the Company had outstanding borrowings of $600.5 million and had standby letters of credit of $49.5 million, which reduce the availability of the undrawn borrowing base. As of the date of this filing, the available balance under the credit facility was zero.

Principal amounts borrowed on the credit facility will be payable on the maturity date. We may repay any amounts borrowed prior to the maturity date without any premium or penalty other than customary LIBOR breakage costs. Amounts repaid under the credit facility may be re-borrowed from time to time, subject to the terms of the facility.

Interest on the credit facility is payable at one of the following two variable rates as selected by the Company: a base rate based on the Prime Rate or the Eurodollar rate, based on LIBOR. Either rate is adjusted upward by an applicable margin, based on the utilization percentage of the facility as outlined in the pricing grid below. Additionally, the credit facility provides for a commitment fee of 0.375% to 0.50%, depending on borrowing base usage. The grid below shows the Base Rate Margin and Eurodollar Margin depending on the applicable Borrowing Base Utilization Percentage (as defined in the credit facility) as of the date of this filing:

Borrowing Base Utilization Grid

Borrowing Base Utilization Percentage	Utilization	Eurodollar Margin	Base Rate Margin	Commitment Fee Rate
Level 1	<25%	1.50 %	0.50 %	0.38 %
Level 2	≥ 25% < 50%	1.75 %	0.75 %	0.38 %
Level 3	≥ 50% < 75%	2.00 %	1.00 %	0.50 %
Level 4	≥ 75% < 90%	2.25 %	1.25 %	0.50 %
Level 5	≥90%	2.50 %	1.50 %	0.50 %

The credit facility contains representations, warranties, covenants, conditions and defaults customary for transactions of this type, including but not limited to: (i) limitations on liens and incurrence of debt covenants; (ii) limitations on dividends, distributions, redemptions and restricted payments covenants; (iii) limitations on investments, loans and advances covenants; and (iv) limitations on the sale of property, mergers, consolidations and other similar transactions covenants. Additionally, the credit facility limits the Company entering into hedges in excess of 85% of its anticipated production volumes.

The credit facility also contains financial covenants requiring the Company to comply on the last day of each quarter with a current ratio of its restricted subsidiaries' current assets (includes availability under the revolving credit facility and unrestricted cash and excludes derivative assets) to its restricted subsidiaries' current liabilities (excludes obligations under the revolving credit facility, senior notes and certain derivative liabilities), of not less than 1.0 to 1.0 and to maintain, on the last day of each quarter, a ratio of its restricted subsidiaries' debt less cash balances to its restricted subsidiaries EBITDAX (EBITDAX is defined as net income adjusted for interest expense, income tax expense/benefit, DD&A, exploration and abandonment expenses as well as certain non-recurring cash and non-cash charges and income (such as stock-based compensation expense, unrealized gains/losses on commodity derivatives and impairment of long-lived assets and goodwill), subject to pro forma adjustments for non-ordinary course acquisitions and divestitures) for the four fiscal quarter periods most recently ended, of not greater than 4.0 to 1.0 as of the last day of such fiscal quarter. As of March 31, 2020, the Company was in compliance with the covenants under the credit agreement.

The Company's 2020 capital program remains focused on generating free cash flow with an emphasis on strengthening liquidity and the balance sheet as the Company works to pay down debt. However, factors including those outside of the Company's control may prevent maintaining compliance with such covenants, including commodity price declines and the Company's inability to access capital markets, to access the asset sale market or to execute on its business plan. Additionally, as a result of the reduction of the borrowing base and elected commitments described above, it is probable that the Company will not meet the financial covenants under the revolving credit facility for the three months ended June 30, 2020 under the Company's current financial forecast. The Company may seek covenant relief from the lenders under the revolving credit facility, and if the Company does not obtain a waiver of its financial covenants for the three months ended June 30, 2020, the lenders under the revolving credit facility will be able to declare all outstanding principal and interest to be due and payable, and the lenders under the credit agreement could terminate their commitments to loan money and could foreclose against the assets collateralizing their borrowings. Any acceleration of the obligations under the revolving credit facility would result in a cross-default and potential acceleration of the maturity of the Company's other outstanding long-term debt.

Any borrowings under the credit facility are collateralized by substantially all of the assets of the Company and certain of its subsidiaries, including oil and gas properties, personal property and the equity interests of those subsidiaries of the Company. The Company has entered into oil and natural gas hedging transactions with several counterparties that are also lenders under the credit facility. The Company's obligations under these hedging contracts are secured by the collateral securing the credit facility. Elevation is an unrestricted subsidiary, which is no longer consolidated or controlled by the Company, and the assets and credit of Elevation are not available to satisfy the debts and other obligations of the Company or its other subsidiaries.

2024 Senior Notes

In August 2017, the Company issued at par $400.0 million principal amount of 7.375% Senior Notes due May 15, 2024 (the "2024 Senior Notes" and the offering, the "2024 Senior Notes Offering"). The 2024 Senior Notes bear an annual interest rate of 7.375%. The interest on the 2024 Senior Notes is payable on May 15 and November 15 of each year which commenced on November 15, 2017. The Company received net proceeds of approximately $392.6 million after deducting fees.

The Company's 2024 Senior Notes are its senior unsecured obligations and rank equally in right of payment with all of its other senior indebtedness and senior to any of its subordinated indebtedness. The Company's 2024 Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by certain of the Company's current subsidiaries and by certain future restricted subsidiaries that guarantees its indebtedness under a credit facility (the "2024 Senior Notes Guarantors"). The 2024 Senior Notes are effectively subordinated to all of the Company's secured indebtedness (including all borrowings and other obligations under its revolving credit facility) to the extent of the value of the collateral securing such indebtedness, and structurally subordinated in right of payment to all existing and future indebtedness and other liabilities (including trade payables) of any of its future subsidiaries that do not guarantee the 2024 Senior Notes.

The 2024 Senior Notes also contain affirmative and negative covenants that, among other things, limit the Company's and the 2024 Senior Notes Guarantors' ability to make investments; declare or pay any dividend or make any other payment to holders of the Company’s or any of its 2024 Senior Notes Guarantors’ equity interests; repurchase or redeem any equity interests of the Company; repurchase or redeem subordinated indebtedness; incur additional indebtedness or issue preferred stock; create liens; sell assets; enter into agreements that restrict dividends or other payments by restricted subsidiaries; consolidate, merge or transfer all or substantially all of the assets of the Company; engage in transactions with the Company's affiliates; engage in any business other than the oil and gas business; and create unrestricted subsidiaries. The indenture governing the 2024 Senior Notes also contains customary events of default. Upon the occurrence of events of default arising from certain events of bankruptcy or insolvency, the 2024 Senior Notes shall become due and payable immediately without any declaration or other act of the trustee or the holders of the 2024 Senior Notes. Upon the occurrence of certain other events of default, the trustee or the holders of at least 25% in aggregate principal amount of the then outstanding 2024 Senior Notes may declare all outstanding 2024 Senior Notes to be due and payable immediately.

2026 Senior Notes

In January 2018, the Company issued at par $750.0 million principal amount of 5.625% Senior Notes due February 1, 2026 (the "2026 Senior Notes" and together with the 2024 Senior Notes, the "Senior Notes" and the offering of the 2026 Senior Notes, the "2026 Senior Notes Offering"). The 2026 Senior Notes bear an annual interest rate of 5.625%. The interest on the 2026 Senior Notes is payable on February 1 and August 1 of each year commencing on August 1, 2018. The Company received net proceeds of approximately $737.9 million after deducting fees.

The Company's 2026 Senior Notes are the Company's senior unsecured obligations and rank equally in right of payment with all of the Company's other senior indebtedness and senior to any of the Company's subordinated indebtedness. The Company's 2026 Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by certain of the Company's current subsidiaries and by certain future restricted subsidiaries that guarantee the Company's indebtedness under a credit facility (the "2026 Senior Notes Guarantors"). The 2026 Senior Notes are effectively subordinated to all of the Company's secured indebtedness (including all borrowings and other obligations under the Company's revolving credit facility) to the extent of the value of the collateral securing such indebtedness, and structurally subordinated in right of payment to all existing and future indebtedness and other liabilities (including trade payables) of certain of the Company's future restricted subsidiaries that do not guarantee the 2026 Senior Notes.

The 2026 Senior Notes also contain affirmative and negative covenants that, among other things, limit the Company's and the 2026 Senior Notes Guarantors' ability to make investments; declare or pay any dividend or make any other payment to holders of the Company's or any of its 2026 Senior Notes Guarantors' equity interests; repurchase or redeem any equity interests of the Company; repurchase or redeem subordinated indebtedness; incur additional indebtedness or issue preferred stock; create liens; sell assets; enter into agreements that restrict dividends or other

payments by restricted subsidiaries; consolidate, merge or transfer all or substantially all of the assets of the Company; engage in transactions with the Company's affiliates; engage in any business other than the oil and gas business; and create unrestricted subsidiaries. The indenture governing the 2026 Senior Notes also contains customary events of default. Upon the occurrence of events of default arising from certain events of bankruptcy or insolvency, the 2026 Senior Notes shall become due and payable immediately without any declaration or other act of the trustee or the holders of the 2026 Senior Notes. Upon the occurrence of certain other events of default, the trustee or the holders of at least 25% in aggregate principal amount of the then outstanding 2026 Senior Notes may declare all outstanding 2026 Senior Notes to be due and payable immediately.

Debt Issuance Costs

As of March 31, 2020, the Company had debt issuance costs, net of accumulated amortization, of $2.2 million related to its credit facility which has been reflected on the Company's condensed consolidated balance sheets within the line item other non-current assets. As of March 31, 2020, the Company had debt issuance costs net of accumulated amortization of $13.8 million related to its 2024 and 2026 Senior Notes which have been reflected on the Company's condensed consolidated balance sheets within the line item Senior Notes, net of unamortized debt issuance costs. Debt issuance costs include origination, legal, engineering, and other fees incurred in connection with the Company's credit facility and Senior Notes. For the three months ended March 31, 2020 and March 31, 2019, the Company recorded amortization expense related to the debt issuance costs of $1.2 million and $1.5 million, respectively.

Interest Incurred on Long-Term Debt

For the three months ended March 31, 2020, the Company incurred interest expense on long-term debt of $22.3 million as compared to $20.8 million for the three months ended March 31, 2019. For the three months ended March 31, 2020, the Company capitalized interest expense on long term debt of $2.1 million as compared to $2.0 million for the three months ended March 31, 2019, which has been reflected in the Company's consolidated financial statements.

Senior Note Repurchase Program

On January 4, 2019, the Board of Directors authorized a program to repurchase up to $100.0 million of the Company's Senior Notes (the "Senior Notes Repurchase Program"). The Company's Senior Notes Repurchase Program is subject to restrictions under our credit facility and does not obligate it to acquire any specific nominal amount of Senior Notes. For the three months ended March 31, 2020, the Company did not repurchase any Senior Notes. For the three months ended March 31, 2019, the Company repurchased a nominal value of $35.8 million for $28.5 million in connection with the Senior Notes Repurchase Program. Interest expense for the three months ended March 31, 2019 included a $7.3 million gain on debt repurchase related to the Company's Senior Note Repurchase Program.

Note 6—Commodity Derivative Instruments

The Company has entered into commodity derivative instruments, as described below. The Company has utilized swaps, put options and call options to reduce the effect of price changes on a portion of the Company's future oil and natural gas production.

A swap has an established fixed price. When the settlement price is below the fixed price, the counterparty pays the Company an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume. When the settlement price is above the fixed price, the Company pays its counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume.

A put option has an established floor price. The buyer of the put option pays the seller a premium to enter into the put option. When the settlement price is below the floor price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is above the floor price, the put option expires worthless. Some of the Company's purchased put options have deferred premiums. For the deferred premium puts, the Company agrees to pay a premium to the counterparty at the time of settlement.

A call option has an established ceiling price. The buyer of the call option pays the seller a premium to enter into the call option. When the settlement price is above the ceiling price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is below the ceiling price, the call option expires worthless.

The Company combines swaps, purchased put options, purchased call options, sold put options and sold call options in order to achieve various hedging strategies. Some examples of the Company's hedging strategies are collars which include purchased put options and sold call options, three-way collars which include purchased put options, sold put options and sold call options, and enhanced swaps, which include either sold put options or sold call options with the associated premiums rolled into an enhanced fixed price swap.

The objective of the Company's use of commodity derivative instruments is to achieve more predictable cash flows in an environment of volatile oil and gas prices and to manage its exposure to commodity price risk. While the use of these commodity derivative instruments limits the downside risk of adverse price movements, such use may also limit the Company's ability to benefit from favorable price movements. The Company may, from time to time, add incremental derivatives to hedge additional production, restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of the Company's existing positions. The Company does not enter into derivative contracts for speculative purposes.

To reduce the impact of fluctuations in oil and natural gas prices on our revenues, we have periodically entered into commodity derivative contracts with respect to certain of our oil and natural gas production through various transactions that limit the downside of future prices received. We plan to continue our practice of entering into such transactions to reduce the impact of commodity price volatility on our cash flow from operations. Future transactions may include price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty. Additionally, we may enter into collars, whereby we receive the excess, if any, of the fixed floor over the floating rate or pay the excess, if any, of the floating rate over the fixed ceiling price. These hedging activities are intended to support oil prices at targeted levels and to manage our exposure to oil price fluctuations.

The use of derivatives involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts. The Company's derivative contracts are currently with nine counterparties, all but one of whom are lenders under our credit agreement. The Company has netting arrangements with the counterparties that provide for the offset of payables against receivables from separate derivative arrangements with the counterparties in the event of contract termination. The derivative contracts may be terminated by a non-defaulting party in the event of default by one of the parties to the agreement. There is no credit risk related contingent features or circumstances in which the features could be triggered in derivative instruments that are in a net liability position at the end of the reporting period.

The Company's commodity derivative contracts as of March 31, 2020 are summarized below:

	2020	2021	2022	2023
NYMEX WTI Crude Swaps:				
Notional volume (Bbl)	2,800,000	4,200,000	1,020,000	900,000
Weighted average fixed price ($/Bbl)	$ 59.75	$ 57.10	$ 54.84	$ 54.87
NYMEX WTI Crude Purchased Puts:				
Notional volume (Bbl)	5,300,000	3,600,000	—	—
Weighted average purchased put price ($/Bbl)	$ 54.83	$ 54.17	$ —	$ —
NYMEX WTI Crude Purchased Calls:				
Notional volume (Bbl)	250,000	—	—	—
Weighted average purchased call price ($/Bbl)	$ 57.06	$ —	$ —	$ —
NYMEX WTI Crude Sold Calls:				
Notional volume (Bbl)	6,250,000	3,600,000	—	—
Weighted average sold call price ($/Bbl)	$ 61.94	$ 61.93	$ —	$ —
NYMEX WTI Crude Sold Puts:				
Notional volume (Bbl)	8,100,000	7,800,000	600,000	600,000
Weighted average sold put price ($/Bbl)	$ 43.08	$ 43.27	$ 43.00	$ 43.00
NYMEX HH Natural Gas Swaps:				
Notional volume (MMBtu)	27,000,000	—	—	—
Weighted average fixed price ($/MMBtu)	$ 2.75	$ —	$ —	$ —
CIG Basis Gas Swaps:				
Notional volume (MMBtu)	34,200,000	2,400,000	—	—
Weighted average fixed basis price ($/MMBtu)	$ (0.61)	$ (0.57)	$ —	$ —

The following tables detail the fair value of the Company's derivative instruments, including the gross amounts and adjustments made to net the derivative instruments for the presentation in the condensed consolidated balance sheets (in thousands):

	As of March 31, 2020				
Location on Balance Sheet	**Gross Amounts of Recognized Assets and Liabilities**	**Gross Amounts Offsets in the Balance Sheet[1]**	**Net Amounts of Assets and Liabilities Presented in the Balance Sheet**	**Gross Amounts not Offset in the Balance Sheet[2]**	**Net Amounts[3]**
Current assets	$ 293,761	$ (129,431)	$ 164,330	$ (716)	$ 252,397
Non-current assets	127,705	(38,922)	88,783	—	—
Current liabilities	(130,147)	129,431	(716)	716	—
Non-current liabilities	(38,922)	38,922	—	—	—

	As of December 31, 2019				
Location on Balance Sheet	**Gross Amounts of Recognized Assets and Liabilities**	**Gross Amounts Offsets in the Balance Sheet[1]**	**Net Amounts of Assets and Liabilities Presented in the Balance Sheet**	**Gross Amounts not Offset in the Balance Sheet[2]**	**Net Amounts[3]**
Current assets	$ 48,605	$ (31,051)	$ 17,554	$ —	$ 30,783
Non-current assets	38,034	(24,805)	13,229	—	—
Current liabilities	(33,049)	31,051	(1,998)	—	(2,106)
Non-current liabilities	(24,913)	24,805	(108)	—	—

(1) Agreements are in place that allow for the financial right of offset for derivative assets and derivative liabilities at settlement or in the event of a default under the agreements.
(2) Netting for balance sheet presentation is performed by current and non-current classification. This adjustment represents amounts subject to an enforceable master netting arrangement, which are not netted on the condensed consolidated balance sheets. There are no amounts of related financial collateral received or pledged.
(3) Net amounts are not split by current and non-current. All counterparties in a net asset position are shown in the current asset line, and all counterparties in a net liability position are shown in the current liability line item.

The table below sets forth the commodity derivatives gain (loss) for the three months ended March 31, 2020 and 2019 (in thousands). Commodity derivatives gain (loss) are included under the other income (expense) line item in the condensed consolidated statements of operations.

	For the Three Months Ended March 31,	
	2020	2019
Commodity derivatives gain (loss)	$ 263,015	$ (122,091)

Note 7—Asset Retirement Obligations

The Company follows accounting for asset retirement obligations in accordance with ASC 410, *Asset Retirement and Environmental Obligations*, which requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it was incurred if a reasonable estimate of fair value could be made. The Company's asset retirement obligations primarily represent the estimated present value of the amounts expected to be incurred to plug, abandon and remediate producing and shut-in wells at the end of their productive lives in accordance with applicable local, state and federal laws, and applicable lease terms. The Company determines the estimated fair value of its asset retirement obligations by calculating the present value of estimated cash flows related to plugging and abandonment liabilities. The significant inputs used to calculate such liabilities include estimates of costs to be incurred, the Company's credit adjusted discount rates, inflation rates and estimated dates of abandonment. The asset retirement liability is accreted to its present value each period and the capitalized asset retirement costs are depleted with proved oil and gas properties using the unit of production method.

The following table summarizes the activities of the Company's asset retirement obligations for the period indicated (in thousands):

	For the Three Months Ended March 31, 2020
Balance beginning of period	$ 95,908
Liabilities incurred or acquired	192
Liabilities settled	(10,787)
Revisions in estimated cash flows	6,638
Accretion expense	1,822
Balance end of period	$ 93,773

Note 8—Fair Value Measurements

ASC 820, *Fair Value Measurement and Disclosure*, establishes a hierarchy for inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. Observable inputs are inputs that market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the Company. Unobservable inputs are inputs that reflect the Company's assumptions of what market participants would use in pricing the asset or liability developed based on the best information available in the circumstances. The hierarchy is broken down into three levels based on the reliability of the inputs as follows:

- Level 1: Quoted prices are available in active markets for identical assets or liabilities;
- Level 2: Quoted prices in active markets for similar assets and liabilities that are observable for the asset or liability;
- Level 3: Unobservable pricing inputs that are generally less observable from objective sources, such as discounted cash flow models or valuations.

The financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. There were no transfers between levels during any periods presented below.

The following table presents the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2020 and December 31, 2019 by level within the fair value hierarchy (in thousands):

	Fair Value Measurement at March 31, 2020			
	Level 1	Level 2	Level 3	Total
Financial Assets:				
Commodity derivative assets	$ —	$ 253,113	$ —	$ 253,113
Financial Liabilities:				
Commodity derivative liabilities	$ —	$ 716	$ —	$ 716

	Fair Value Measurement at December 31, 2019			
	Level 1	Level 2	Level 3	Total
Financial Assets:				
Commodity derivative assets	$ —	$ 30,783	$ —	$ 30,783
Financial Liabilities:				
Commodity derivative liabilities	$ —	$ 2,106	$ —	$ 2,106

The following methods and assumptions were used to estimate the fair value of the assets and liabilities in the tables above:

Commodity Derivative Instruments

The Company determines its estimate of the fair value of derivative instruments using a market based approach that takes into account several factors, including quoted market prices in active markets, implied market volatility factors, quotes from third parties, the credit rating of each counterparty, and the Company's own credit rating. In consideration of counterparty credit risk, the Company assessed the possibility of whether each counterparty to the derivative would default by failing to make any contractually required payments. Additionally, the Company considers that it is of substantial credit quality and has the financial resources and willingness to meet its potential repayment obligations associated with the derivative transactions. Derivative instruments utilized by the Company consist of swaps, put options and, call options. The oil and natural gas derivative markets are highly active. Although the Company's derivative instruments are valued using public indices, the instruments themselves are traded with third party counterparties and are not openly traded on an exchange. As such, the Company has classified these instruments as Level 2.

Fair Value of Financial Instruments

The Company's financial instruments consist primarily of cash and cash equivalents, accounts receivable, accounts payable, commodity derivative instruments (discussed above) and long-term debt. The carrying values of cash and cash equivalents, accounts receivable and accounts payable are representative of their fair values due to their short-term maturities. The carrying amount of the Company's credit facility approximated fair value as it bears interest at

variable rates over the term of the loan. The fair values of the 2024 Senior Notes and 2026 Senior Notes were derived from available market data. As such, the Company has classified the 2024 Senior Notes and 2026 Senior Notes as Level 2. Please refer to *Note 5—Long-Term Debt* for further information. The Company's policy is to recognize transfers between levels at the end of the period. This disclosure (in thousands) does not impact the Company's financial position, results of operations or cash flows.

	At March 31, 2020		At December 31, 2019	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Credit Facility	$ 470,000	$ 470,000	$ 470,000	$ 470,000
2024 Senior Notes[(1)]	$ 395,075	$ 68,000	$ 394,824	$ 250,000
2026 Senior Notes[(2)]	$ 691,272	$ 119,032	$ 690,953	$ 420,113

(1) The carrying amount of the 2024 Senior Notes includes unamortized debt issuance costs of $4.9 million and $5.2 million as of March 31, 2020 and December 31, 2019, respectively.
(2) The carrying amount of the 2026 Senior Notes includes unamortized debt issuance costs of $8.9 million and $9.2 million as of March 31, 2020 and December 31, 2019, respectively.

Non-Recurring Fair Value Measurements

The Company applies the provisions of the fair value measurement standard on a non-recurring basis to its non-financial assets and liabilities, including proved property. These assets and liabilities are not measured at fair value on a recurring basis, but are subject to fair value adjustments when facts and circumstances arise that indicate a need for remeasurement.

The Company utilizes fair value on a non-recurring basis to review its proved oil and gas properties for potential impairment when events and circumstances indicate, and at least annually, a possible decline in the recoverability of the carrying value of such property. The Company uses an income approach analysis based on the net discounted future cash flows of producing property. The future cash flows are based on management's estimates for the future. Unobservable inputs include estimates of oil and gas production, as the case may be, from the Company's reserve reports, commodity prices based on the sales contract terms and forward price curves, operating and development costs and a discount rate based on a market-based weighted average cost of capital (all of which are Level 3 inputs within the fair value hierarchy). For the three months ended March 31, 2020 and 2019, the Company recognized $0.8 million and $8.2 million, respectively, in impairment expense on its proved oil and gas properties related to impairment of assets in its northern field. The fair value did not exceed the Company's carrying amount associated with its proved oil and gas properties in its northern field.

Note 9—Income Taxes

The Company computes an estimated annual effective tax rate ("AETR") each quarter based on the current and forecasted operating results. The income tax expense or benefit associated with the interim period is computed using the most recent estimated AETR applied to the year-to-date ordinary income or loss, plus the tax effect of any significant or infrequently occurring items recorded during the interim period. The computation of the estimated AETR at each interim period requires certain estimates and significant judgements including, but not limited to, the expected operating income (loss) for the year, projections of the proportion of income earned and taxed in various jurisdictions, permanent differences and the likelihood of recovering deferred tax assets generated in the current year. The accounting estimates used to compute the provision for income taxes may change as new events occur, more experience is obtained, and additional information becomes known or as the tax environment changes.

The effective combined U.S. federal and state income tax rate for the three months ended March 31, 2020 and 2019 was 19.6% and 23.6%, respectively. The effective rate for the three months ended March 31, 2020 and 2019 differs from the amount that would be provided by applying the statutory U.S. federal income tax rate of 21% to pre-tax income due to (i) the effect of a full valuation allowance in effect at March 31, 2020 and (ii) the effects of state taxes, permanent taxable differences, and income attributable to non-controlling interest for the three months ended March 31, 2019.

Before accounting for a naked credit deferred tax liability, net tax expense for the three months ended March 31, 2020 was reduced to zero due to the valuation allowance. The naked credit deferred tax liability results in tax expense of $2.2 million for the three months ended March 31, 2020.

The Company considers whether some portion, or all, of the deferred tax assets ("DTAs") will be realized based on a more likely than not standard of judgment. The ultimate realization of DTAs is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. At December 31, 2019, the Company had a valuation allowance totaling $246.1 million against its DTAs resulting from prior year cumulative financial losses, oil and gas impairments, and significant net operating losses for U.S. federal and state income tax. The Company assesses the appropriateness of its valuation allowance on a quarterly basis. As of March 31, 2020, there was no change in the Company's assessment of the realizability of its DTAs, except for a naked credit deferred tax liability.

Note 10—Stock-Based Compensation

Extraction Long Term Incentive Plan

In October 2016, the Company's board of directors adopted the Extraction Oil & Gas, Inc. 2016 Long Term Incentive Plan (the "2016 Plan" or "LTIP"), pursuant to which employees, consultants and directors of the Company and its affiliates performing services for the Company are eligible to receive awards. The 2016 Plan provides for the grant of stock options, stock appreciation rights, restricted stock, restricted stock units, bonus stock, dividend equivalents, other stock-based awards, substitute awards, annual incentive awards and performance awards intended to align the interests of participants with those of stockholders. In May 2019, the Company's stockholders approved the amendment and restatement of the Company's 2016 Long Term Incentive Plan. The amended and restated 2016 Long Term Incentive Plan provides a total reserve of 32.2 million shares of common stock for issuance pursuant to awards under the LTIP. Extraction has granted awards under the LTIP to certain directors, officers and employees, including stock options, restricted stock units, performance stock awards, performance stock units, performance cash awards and cash awards.

Restricted Stock Units

Restricted stock units granted under the LTIP ("RSUs") generally vest over either a one or three-year service period, with 100% vesting in year one or 25%, 25% and 50% of the units vesting in year one, two and three, respectively. Grant date fair value was determined based on the value of Extraction's common stock pursuant to the terms of the LTIP. The Company assumed a forfeiture rate of zero as part of the grant date estimate of compensation cost.

The Company recorded $0.8 million of stock-based compensation costs related to RSUs for the three months ended March 31, 2020 as compared to $6.9 million for the three months ended March 31, 2019. These costs were included in the condensed consolidated statements of operations within the general and administrative expenses line item. As of March 31, 2020, there was $8.3 million of total unrecognized compensation cost related to the unvested RSUs granted to certain directors, officers and employees that is expected to be recognized over a weighted average period of 2.2 years.

The following table summarizes the RSU activity from January 1, 2020 through March 31, 2020 and provides information for RSUs outstanding at the dates indicated.

	Number of Shares		Weighted Average Grant Date Fair Value
Non-vested RSUs at January 1, 2020	2,635,765	$	8.32
Granted	1,252,000	$	0.31
Forfeited	(351,679)	$	9.44
Vested	(356,008)	$	14.23
Non-vested RSUs at March 31, 2020	3,180,078	$	4.38

Performance Stock Awards

The Company granted performance stock awards ("PSAs") to certain executives under the LTIP in October 2017, March 2018, April 2019 and March 2020. The number of shares of the Company's common stock that may be issued to settle these various PSAs ranges from zero to two times the number of PSAs awarded. PSA's that settle in cash are presented as liability based awards. Generally, the shares issued for PSAs are determined based on the satisfaction of a time-based vesting schedule and a weighting of one or more of the following: (i) absolute total stockholder return ("ATSR"), (ii) relative total stockholder return ("RTSR"), as compared to the Company's peer group and (iii) cash return on capital invested ("CROCI") or return on invested capital ("ROIC") measured over a three-year period and vest in their entirety at the end of the three-year measurement period. Any PSAs that have not vested at the end of the applicable measurement period are forfeited. The vesting criterion that is associated with the RTSR is based on a comparison of the Company's total shareholder return for the measurement period compared to that of a group of peer companies for the same measurement period. As the ATSR and RTSR vesting criteria are linked to the Company's share price, they each are considered a market condition for purposes of calculating the grant-date fair value of the awards. The vesting criterion that is associated with the CROCI and ROIC are considered a performance condition for purposes of calculating the grant-date fair value of the awards.

The fair value of the PSAs was measured at the grant date with a stochastic process method using a Monte Carlo simulation. A stochastic process is a mathematically defined equation that can create a series of outcomes over time. Those outcomes are not deterministic in nature, which means that by iterating the equations multiple times, different results will be obtained for those iterations. In the case of the Company's PSAs, the Company cannot predict with certainty the path its stock price or the stock prices of its peer will take over the performance period. By using a stochastic simulation, the Company can create multiple prospective stock pathways, statistically analyze these simulations, and ultimately make inferences regarding the most likely path the stock price will take. As such, because future stock prices are stochastic, or probabilistic with some direction in nature, the stochastic method, specifically the Monte Carlo Model, is deemed an appropriate method by which to determine the fair value of the PSAs. Significant assumptions used in this simulation include the Company's expected volatility, risk-free interest rate based on U.S. Treasury yield curve rates with maturities consistent with the measurement period as well as the volatilities for each of the Company's peers.

The Company recorded a credit of $0.8 million of stock-based compensation costs related to PSAs for the three months ended March 31, 2020 as compared to $1.5 million of stock-based compensation costs related to PSAs for the three months ended March 31, 2019. These costs were included in the condensed consolidated statements of operations within the general and administrative expenses line item. As of March 31, 2020, there was $5.2 million of total unrecognized compensation cost related to the unvested PSAs granted to certain executives that is expected to be recognized over a weighted average period of 2.3 years.

The following table summarizes the PSA activity from January 1, 2020 through March 31, 2020 and provides information for PSAs outstanding at the dates indicated.

	Number of Shares [1]	Weighted Average Grant Date Fair Value
Non-vested PSAs at January 1, 2020	2,863,190	$ 7.72
Granted	5,952,700	$ 0.29
Forfeited	—	$ —
Vested	—	$ —
Non-vested PSAs at March 31, 2020	8,815,890	$ 2.70

(1) The number of awards assumes that the associated maximum vesting condition is met at the target amount. The final number of shares of the Company's common stock issued may vary depending on the performance multiplier, which ranges from zero to one for the 2017 and 2018 grants and ranges from zero to two for the 2019 and 2020 grants, depending on the level of satisfaction of the vesting condition.

Stock Options

Expense on the stock options is recognized on a straight-line basis over the service period of the award less awards forfeited. The fair value of the stock options was measured at the grant date using the Black-Scholes valuation model. The Company utilizes the "simplified" method to estimate the expected term of the stock options granted as there is limited historical exercise data available in estimating the expected term of the stock options. Expected volatility is based on the volatility of the historical stock prices of the Company's peer group. The risk-free rates are based on the yields of U.S. Treasury instruments with comparable terms. A dividend yield and forfeiture rate of zero were assumed. Stock options granted under the LTIP vest ratably over three years and are exercisable immediately upon vesting through the tenth anniversary of the grant date. To fulfill options exercised, the Company will issue new shares.

The Company recorded no stock-based compensation costs related to stock options for the three months ended March 31, 2020, as compared to $3.8 million for the three months ended March 31, 2019. These costs were included in the condensed consolidated statements of operations within the general and administrative expenses line item. As of March 31, 2020, there are no remaining unrecognized compensation costs related to the stock options granted to certain executives.

There was no stock option activity from January 1, 2020 through March 31, 2020. However, as of March 31, 2020, there was approximately 5.2 million outstanding and exercisable stock options with a weighted-average exercise price of $18.50.

Incentive Restricted Stock Units

Officers of the Company contributed 2.7 million shares of common stock to Extraction Employee Incentive, LLC ("Employee Incentive"), which is owned solely by certain officers of the Company. Employee Incentive issued restricted stock units ("Incentive RSUs") to certain employees. Incentive RSUs vested over a three year service period, with 25%, 25% and 50% of the units vesting in year one, two and three, respectively. On July 17, 2017, the partners of Employee Incentive amended the vesting schedule in which 25% vested immediately and the remaining Incentive RSUs vest 25%, 25% and 25% each six months thereafter, over the remaining 18-month service period. Grant date fair value was determined based on the value of the Company's common stock on the date of issuance. The Company assumed a forfeiture rate of zero as part of the grant date estimate of compensation cost.

The Company recorded no stock-based compensation costs related to Incentive RSUs for the three months ended March 31, 2020. The Company recorded $0.8 million of stock-based compensation costs related to Incentive RSUs for the three months ended March 31, 2019. These costs were included in the condensed consolidated statements of operations within the general and administrative expenses line item. As of March 31, 2020, there are no remaining unrecognized compensation costs related to the Incentive RSUs granted to certain employees.

Note 11—Equity

Series A Preferred Stock

The holders of our Series A Preferred Stock (the "Series A Preferred Holders") are entitled to receive a cash dividend of 5.875% per year, payable quarterly in arrears, and we have the ability to pay such quarterly dividends in kind at a dividend rate of 10% per year (decreased proportionately to the extent such quarterly dividends are partially paid in cash). We have paid the quarterly dividends in kind since the fourth quarter of 2019, and expect to pay future quarterly dividends in kind. The Series A Preferred Stock is convertible into shares of our common stock at the election of the Series A Preferred Holders at a conversion ratio per share of Series A Preferred Stock of 61.9195. Until the three-year anniversary of the closing of the IPO, we could elect to convert the Series A Preferred Stock at a conversion ratio per share of Series A Preferred Stock of 61.9195, but only if the closing price of our common stock had traded at or above a certain premium to our initial offering price, such premium to decrease with time. On October 15, 2019, the three year anniversary had passed for the Series A Preferred Stock to convert into our common stock. We can now redeem the Series A Preferred Stock at any time for the liquidation preference, which is $194.7 million. In certain situations, including a change of control, the Series A Preferred Stock may be redeemed for cash in an amount equal to the greater of (i) 135% of the liquidation preference of the Series A Preferred Stock and (ii) a 17.5% annualized internal rate of return on the liquidation preference of the Series A Preferred Stock. The Series A Preferred Stock matures on October

15, 2021, at which time they are mandatorily redeemable for cash at the liquidation preference to the extent there are legally available funds to do so. For more information, see the Company's Annual Report.

Elevation Common Units

On May 1, 2020, Elevation's board of managers issued 1,530,000,000 common units at a price of $0.01 per unit to certain of Elevation's members other than Extraction (the "Capital Raise"). The Capital Raise caused Extraction's ownership of Elevation to be diluted to less than 0.01%. As a result of the Capital Raise, beginning in May 2020 Extraction will account for Elevation under the cost method of accounting. The Company reserves all rights related to actions taken by Elevation's board of managers.

Elevation Preferred Units

In July 2018 and July 2019, respectively, Elevation sold 150,000 and 100,000 of Elevation Preferred Units at a price of $990 per unit to a third party (the "Purchaser"). The aggregate liquidation preference when the units were sold was $150.0 million and $100.0 million, respectively. These Preferred Units represent the noncontrolling interest presented on the condensed consolidated balance sheets, condensed consolidated statements of operations and condensed consolidated statements of changes in stockholders' equity and noncontrolling interest. As of March 16, 2020, Elevation is a separate, deconsolidated entity and the assets and credit of Elevation are not available to satisfy the debts and other obligations of the Company or its other subsidiaries. As part of the July 2018 transaction, the Company committed to Elevation that it would drill at least 425 qualifying wells in the acreage dedicated to Elevation by December 31, 2023, subject to reductions if Extraction does not sell the full amount of additional Elevation Preferred Units to the Purchaser. Pursuant to the Fourth Amendment to the Elevation Gathering Agreements between Elevation and Extraction, this drilling commitment would be eliminated, if and only if all Elevation Preferred Units have been redeemed in full or are otherwise no longer outstanding. Please see *Note 13—Commitments and Contingencies — Elevation Gathering Agreements* for further details.

Upon deconsolidation of Elevation Midstream, LLC as discussed in *Note 1—Business and Organization*, the $270.5 million Elevation preferred unit balance in the noncontrolling interest line item of the condensed consolidated balance sheets as of March 31, 2020 was removed. The amount comprises the line item effects of deconsolidation of Elevation Midstream, LLC on the condensed consolidated statements of changes in stockholders' equity and noncontrolling interest as of March 31, 2020.

During the twenty-eight months following the July 3, 2018 Preferred Unit closing date, Elevation is required to pay the Purchaser a quarterly commitment fee payable in cash or in kind of 1.0% per annum on any undrawn amounts of such additional $250.0 million commitment. For the three months ended March 31, 2020 and 2019, respectively, Elevation recognized $0.6 million and $0.9 million of commitment fees paid-in-kind included under the Preferred Unit commitment fees and dividends paid-in-kind line item in the condensed consolidated statements of changes in stockholders' equity and noncontrolling interest.

The Elevation Preferred Units entitle the Purchaser to receive quarterly dividends at a rate of 8.0% per annum. In respect of quarters ending prior to and including June 30, 2020, the Dividend is payable in cash or in kind at the election of Elevation. After June 30, 2020, the Dividend is payable solely in cash. For the three months ended March 31, 2020 and 2019, respectively, Elevation recognized $5.5 million and $3.1 million of dividends paid-in-kind included under the Preferred Unit commitment fees and dividends paid-in-kind line item in the condensed consolidated statements of changes in stockholders' equity and noncontrolling interest.

Note 12—Earnings (Loss) Per Share

Basic earnings per share ("EPS") includes no dilution and is computed by dividing net income (loss) available to common shareholders by the weighted average number of shares outstanding during the period. Diluted EPS reflects the potential dilution of securities that could share in the earnings of the Company.

The Company uses the "if-converted" method to determine potential dilutive effects of the Company's outstanding Series A Preferred Stock and the treasury method to determine the potential dilutive effects of outstanding

restricted stock awards and stock options. The basic weighted average shares outstanding calculation is based on the actual days in which the shares were outstanding for the three months ended March 31, 2020 and 2019.

The components of basic and diluted EPS were as follows (in thousands, except per share data):

	For the Three Months Ended March 31,	
	2020	2019
Basic and Diluted Income (Loss) Per Share		
Net income (loss)	$ 9,037	$ (94,032)
Less: Noncontrolling interest	(6,160)	(3,975)
Less: Adjustment to reflect Series A Preferred Stock dividends	(4,748)	(2,721)
Less: Adjustment to reflect accretion of Series A Preferred Stock discount	(1,770)	(1,596)
Adjusted net loss available to common shareholders, basic and diluted	$ (3,641)	$ (102,324)
Denominator:		
Weighted average common shares outstanding, basic and diluted [1] [2]	137,726	170,702
Loss Per Common Share		
Basic and diluted	$ (0.03)	$ (0.60)

(1) For the three months ended March 31, 2020, 8,339,698 potentially dilutive shares, including restricted stock awards and stock options outstanding, were not included in the calculation above, as they had an anti-dilutive effect on EPS. Additionally, 11,472,445 common shares associated with the assumed conversion of Series A Preferred Stock were also excluded, as they would have had an anti-dilutive effect on EPS.

(2) For the three months ended March 31, 2019, 8,017,004 potentially dilutive shares, including restricted stock awards and stock options outstanding, were not included in the calculation above, as they had an anti-dilutive effect on EPS. Additionally, 11,472,445 common shares associated with the assumed conversion of Series A Preferred Stock were also excluded, as they would have had an anti-dilutive effect on EPS.

Note 13—Commitments and Contingencies

General

As is customary in the oil and gas industry, the Company may at times have commitments in place to reserve or earn certain acreage positions or wells. If the Company does not meet such commitments, the acreage positions or wells may be lost, or the Company may be required to pay damages if certain performance conditions are not met.

Leases

The Company has entered into operating leases for certain office facilities, compressors and office equipment. Maturities of operating lease liabilities associated with right-of-use assets and including imputed interest were as follows (in thousands):

	As of March 31, 2020		As of December 31, 2019
2020 - remaining	13,653	2020	19,040
2021	5,247	2021	5,247
2022	2,211	2022	2,211
2023	2,246	2023	2,246
2024	2,301	2024	2,301
Thereafter	8,273	Thereafter	8,273
Total lease payments	33,931	Total lease payments	39,318
Less imputed interest [1]	(4,264)	Less imputed interest [1]	(4,735)
Present value of lease liabilities [2]	$ 29,667	Present value of lease liabilities [2]	$ 34,583

(1) Calculated using the estimated interest rate for each lease.

(2) Of the total present value of lease liabilities as of March 31, 2020 and December 31, 2019, $15.2 million and $17.4 thousand, respectively, were recorded in accounts payable and accrued liabilities and $14.5 million and $17.2 thousand, respectively, were recorded in other non-current liabilities on the condensed consolidated balance sheets.

Drilling Rigs

As of March 31, 2020, the Company was subject to commitments on two drilling rigs contracted through May 2020 and February 2021. These costs are capitalized within proved oil and gas properties on the condensed consolidated balance sheets and are included as short-term lease costs. In the event of early termination of these contracts, the Company would be obligated to pay an aggregate amount of approximately $9.0 million as of March 31, 2020, as required under the terms of the contracts. Subsequent to March 31, 2020, the Company renegotiated the terms of the drilling rig contracts. After the modifications, in the event of early termination, the Company would be obligated to pay an aggregate amount of approximately $8.0 million as of May 6, 2020.

Delivery Commitments

As of March 31, 2020, the Company's oil marketer is subject to a firm transportation agreement that commenced in November 2016 and has a ten-year term with a monthly minimum delivery commitment of 45,000 Bbl/d in year one, 55,800 Bbl/d in year two, 61,800 Bbl/d in years three through seven and 58,000 Bbl/d in years eight through ten. In May 2017, the Company amended its agreement with its oil marketer that requires it to sell all of its crude oil from an area of mutual interest in exchange for a make-whole provision that allows the Company to satisfy any minimum volume commitment deficiencies incurred by its oil marketer with future barrels of crude oil in excess of their minimum volume commitment during the contract term. In May 2019, the Company extended the term of this agreement through October 31, 2020 subject to an evergreen provision thereafter where either party can provide a six month notice of termination beginning November 1, 2020. Due to the contract termination date, the amount of consideration recognized in revenue is reduced. Please see *Note 2—Basis of Presentation, Significant Accounting Policies and Recent Accounting Pronouncements — Revenue — Contract Balances*. The Company has posted a letter of credit for this agreement in the amount of $40.0 million. The Company may be required to pay a shortfall fee for any volume deficiencies under these commitments. The aggregate remaining amount of estimated payments under these agreements is approximately $655.8 million.

The Company has two long-term crude oil gathering commitments with a unconsolidated subsidiary, in which the Company had a minority ownership interest. Please see *Note 1—Business and Organization* for information related to the deconsolidation of Elevation Midstream, LLC. The first agreement commenced in November 2016 and has a term of ten years with a minimum volume commitment of an average of 9,167 Bbl/d in year one, 17,967 Bbl/d in year two, 18,800 Bbl/d for years three through five and 10,000 Bbl/d for years six through ten. The Company may be required to pay a shortfall fee for any volume deficiencies under this commitment. The second agreement commenced in July 2019 and has a term of ten years for an average of 3,200 Bbl/d in year one, 8,000 Bbl/d in year two, 14,000 Bbl/d in year three, 16,000 Bbl/d in years four through eight, 12,000 Bbl/d in year nine and 10,000 Bbl/d in year ten. The Company may be

required to pay a shortfall fee for any volume deficiencies under this commitment. The aggregate remaining amount of estimated payments under these agreements is approximately $117.7 million.

In February 2019, the Company entered into two long-term gas gathering and processing agreements with third-party midstream providers. One of the agreements additionally includes a long-term NGL sales commitment for take-in-kind NGLs from other processing agreements. The first agreement commenced in November 2019 and has a term of twenty years with a minimum volume commitment of 251 Bcf to be delivered within the first seven years. The annual commitments over seven years are to be delivered on an average 85,000 Mcf/d in year one, 125,000 Mcf/d in year two, 140,000 Mcf/d in year three, 118,000 Mcf/d in year four, 98,000 Mcf/d in year five, 70,000 Mcf/d in year six and 52,000 Mcf/d in year seven. The aggregate remaining amount of estimated payments under this agreement is approximately $299.3 million. The second agreement commenced on January 2020 and has a term of ten years with an annual minimum volume commitment of 13.0 Bcf in years one through ten. The second agreement also includes a commitment to sell take-in-kind NGLs of 4,000 Bbl/d in year one and 7,500 Bbl/d in years two through seven with the ability to roll up to a 10% shortfall in a given month to the subsequent month. The Company may be required to pay a shortfall fee for any volume deficiencies under these commitments, calculated based on the applicable gathering and processing fees and/or, with respect to the NGL commitment, the NGL transport cost. Under its current drilling plans, the Company expects to meet these volume commitments.

The summary of these minimum volume commitments as of March 31, 2020, was as follows:

	Oil (MBbl)	Gas (MMcf)	Total (MBOE)
2020 - remaining	6,492	25,815	10,794
2021	9,797	46,540	17,554
2022	8,944	49,758	17,237
2023	9,490	41,850	16,465
2024	9,516	34,160	15,209
Thereafter	29,860	40,260	36,570
Total	74,099	238,383	113,829

In collaboration with several other producers and a midstream provider, on December 15, 2016 and August 7, 2017, the Company agreed to participate in expansions of natural gas gathering and processing capacity in the DJ Basin. The plan includes two new processing plants as well as the expansion of related gathering systems. The first plant commenced operations in August 2018 and the second plant commenced operations in July 2019. The Company's share of these commitments will require an incremental 51.5 and 20.6 MMcf per day, respectively, over a baseline volume of 65 MMcf per day to be delivered after the plants' in-service dates for a period of seven years thereafter. The Company may be required to pay a shortfall fee for any incremental volume deficiency under these commitments. These contractual obligations can be reduced by the Company's proportionate share of the collective volumes delivered to the plants by other third-party incremental volumes available to the midstream provider at the new facilities that are in excess of the total commitments. The Company is also required for the first three years of each contract to guarantee a certain target profit margin on these volumes sold.

In July 2019, the Company entered into three long-term contracts to supply 125,000 dekatherms of residue gas per day for five years to a transportation company. While our production is expected to satisfy these contracts, the aggregate remaining amount of estimated commitment assuming no production is $31.0 million. The Company has posted a letter of credit for this agreement in the amount of $8.7 million.

The aggregate remaining amount of estimated remaining payments under these agreements is $1,103.8 million.

Elevation Gathering Agreements

In November 2018, the Company entered into three long-term gathering agreements (the "Elevation Gathering Agreements") for gas, crude oil and produced water with Elevation. Under the agreements, the Company agreed to drill 100 wells in Broomfield and 325 wells in Hawkeye by December 31, 2023 if both facilities are to be built. Elevation has alleged that if the Company fails to complete the wells by the commitment deadline, then it would be in breach of the agreement and Elevation could attempt to assert damages against Extraction and its affiliates. During the first quarter of 2020, Elevation postponed indefinitely further development of gathering systems and facilities that were to be constructed to service the Company's acreage in Hawkeye and another project in the Southwest Wattenberg area. Due to the decision to not complete the Hawkeye facilities and based on the amount of capital invested, the drilling commitment now consists of 297 wells in the Broomfield area of operations.

In April 2019, the Elevation Gathering Agreements were amended to provide for, among other amendments, the inclusion of additional gathering facilities in Elevation’s Badger facility. Pursuant to this amendment, Elevation has asserted that the additional gathering facilities were required to be completed by April 1, 2020 or, within 30 days of such date, Elevation could assert that Extraction must make a payment to Elevation in the amount of 135% of all costs incurred by Elevation as of such date for the development and construction of such additional gathering facilities. As of March 31, 2020, the costs incurred by Elevation for these additional gathering facilities totaled $34.7 million. The Company did not complete these additional gathering facilities by April 1, 2020, and Elevation has alleged that Extraction is in breach of the Elevation Gathering Agreements. On April 2, 2020, Elevation demanded payment of $46.8 million due to an alleged breach in contract stemming from a purported failure to complete the pipeline extensions connecting certain wells to the Badger central gathering facility prior to April 1, 2020. While the Company disputes that these amounts are due to Elevation, under *ASC Topic 450 - Contingencies*, the Company recorded the amount in accounts payable and accrued liabilities, related party on the condensed consolidated balance sheet as of March 31, 2020 and in other operating expenses on the condensed consolidated statements of operations.

In December 2019, the Elevation Gathering Agreements were further amended to provide Elevation additional connection fees that are consistent with market terms (the "Connect Fees"). In the fourth quarter of 2019, the Company incurred $19.5 million for Connect Fees pursuant to the Elevation Gathering Agreements, and in the first quarter of 2020 the Company incurred and paid $23.5 million. The Company does not expect to incur additional Connect Fees for the year ending December 31, 2020.

In March 2020, the Elevation Gathering Agreements were further amended to reset all gathering rates and eliminate existing minimum drilling commitment. This amendment will not become effective until after all Elevation Preferred Units have been redeemed in full or are otherwise no longer outstanding.

Litigation and Legal Items

The Company is involved in various legal proceedings and reviews the status of these proceedings on an ongoing basis and, from time to time, may settle or otherwise resolve these matters on terms and conditions that management believes are in the Company’s best interests. The Company has provided the necessary estimated accruals in the condensed consolidated balance sheets where deemed appropriate for litigation and legal related items that are ongoing and not yet concluded. Although the results cannot be known with certainty, the Company currently believes that the ultimate results of such proceedings will not have a material adverse effect on our business, financial position, results of operations or liquidity.

Environmental. Due to the nature of the natural gas and oil industry, the Company is exposed to environmental risks. The Company has various policies and procedures to minimize and mitigate the risks from environmental contamination or with respect to environmental compliance issues. Liabilities are recorded when environmental damages resulting from past events are probable and the costs can be reasonably estimated. Except as discussed herein, the Company is not aware of any material environmental claims existing as of March 31, 2020 which have not been provided for or would otherwise have a material impact on our financial statements; however, there can be no assurance that current regulatory requirements will not change or that unknown potential past non-compliance with environmental laws, compliance matters or other environmental liabilities will not be discovered on our properties. Accrued environmental liabilities are recorded in accounts payable and accrued liabilities on the condensed consolidated balance sheets. The liability ultimately incurred with respect to a matter may exceed the related accrual.

COGCC Notices of Alleged Violations ("NOAVs"). The Company has received NOAVs from the COGCC for alleged compliance violations that the Company has responded to. At this time, the COGCC has not alleged any specific penalty amounts in these matters. The Company does not believe that any penalties that could result from these NOAVs will have a material effect on our business, financial condition, results of operations or liquidity, but they may exceed $100,000.

Midstream Connections. The Company had dedicated the production from some acreage to a certain midstream service provider. However, the Company was unable to connect well pads to the provider due to the inability to secure right of way access for building the connection pipeline. Because the acreage's production was dedicated to the midstream provider, they have invoiced the Company for oil and gas handled by other midstream providers. The Company disputes these invoices based on force majeure and may have other contractual or legal defenses. The Company's maximum exposure as of March 31, 2020 was $15.7 million. As of March 31, 2020, no contingent liability has been recorded as the amount of the loss cannot be reasonably estimated.

Elevation Matador Facility. Under the Elevation LLC Agreement, the Company is required to complete the gathering facilities in Elevation's Matador facility servicing the Company's Hawkeye area by August 1, 2020. As part of the Company's abandonment of further developing this Matador gathering system and facilities that were being constructed, Elevation has alleged that Extraction will be required to reimburse Elevation for all such expenditures on this project. Elevation is currently disputing certain costs related to this project with a third-party contractor that was working on the project. The Company's maximum exposure as of March 31, 2020 was $20.7 million. As of March 31, 2020, no contingent liability has been recorded as the amount of the loss cannot be reasonably estimated.

Elevation Gathering. As discussed above under *Elevation Gathering Agreements*, on April 2, 2020, Elevation demanded payment of $46.8 million due to an alleged breach in contract stemming from a purported failure to complete the pipeline extensions connecting certain wells to the Badger central gathering facility prior to April 1, 2020. While the Company disputes that these amounts are due to Elevation, under *ASC Topic 450 - Contingencies*, the Company recorded the amount in accounts payable and accrued liabilities, related party on the condensed consolidated balance sheet as of March 31, 2020 and in other operating expenses on the condensed consolidated statements of operations.

Note 14—Related Party Transactions

2024 Senior Notes

Several 5% stockholders of the Company were also holders of the 2024 Senior Notes. As of the initial issuance in August 2017 of the $400.0 million principal amount on the 2024 Senior Notes, such stockholders held $54.9 million.

2026 Senior Notes

Several holders of the 2026 Senior Notes are also 5% stockholders of the Company. As of the initial issuance in January 2018 of the $750.0 million principal amount on the 2026 Senior Notes, such stockholders held $56.2 million.

Elevation Midstream, LLC

As discussed in *Note 13—Commitments and Contingencies*, on April 2, 2020, Elevation demanded payment of $46.8 million due to an alleged breach in contract stemming from a purported failure to complete the pipeline extensions connecting certain wells to the Badger central gathering facility prior to April 1, 2020. While the Company disputes that these amounts are due to Elevation, under *ASC Topic 450 - Contingencies*, the Company recorded the amount in accounts payable and accrued liabilities, related party on the condensed consolidated balance sheet as of March 31, 2020 and in other operating expenses on the condensed consolidated statements of operations.

Note 15—Segment Information

Beginning in the fourth quarter of 2018, the Company had two operating segments, (i) the exploration, development and production of oil, natural gas and NGL (the "exploration and production segment") and (ii) the construction of and support of midstream assets to gather and process crude oil and gas production (the "gathering and facilities segment"). Elevation Midstream, LLC comprised the gathering and facilities segment. During the three months ending March 31, 2019, the Company's gathering and facilities segment was in the construction phase and no revenue generating activities had commenced. Through March 16, 2020, the results of Elevation were included in the consolidated financial statements of Extraction. Effective March 17, 2020, the results of Elevation Midstream, LLC are no longer consolidated in Extraction's results; however, the Company's segment disclosures include the gathering and facilities segment because it was consolidated through March 16, 2020. Please see *Note 1—Business and Organization* for further information related to the deconsolidation of Elevation Midstream, LLC. After March 31, 2020, Extraction will report as a single operating segment.

The following table presents a reconciliation of Adjusted EBITDAX by segment to the GAAP financial measure of income (loss) before income taxes for the three months ended March 31, 2020 and 2019 (in thousands).

	For the Three Months Ended March 31,	
	2020	2019
Reconciliation of Adjusted EBITDAX to Income (Loss) Before Income Taxes		
Exploration and production segment EBITDAX	$ 122,639	$ 138,339
Gathering and facilities segment EBITDAX	1,256	(152)
Subtotal of Reportable Segments	$ 123,895	$ 138,187
Less:		
Depletion, depreciation, amortization and accretion	$ (76,051)	$ (118,770)
Impairment of long lived assets	(775)	(8,248)
Other operating expenses	(52,575)	—
Exploration and abandonment expenses	(112,480)	(6,194)
Gain on sale of property and equipment	—	222
Gain (loss) on commodity derivatives	263,015	(122,091)
Settlements on commodity derivative instruments	(39,295)	10,329
Premiums paid for derivatives that settled during the period	—	9,549
Stock-based compensation expense	—	(13,008)
Amortization of debt issuance costs	(1,242)	(1,497)
Gain on repurchase of 2026 Senior Notes	—	7,317
Interest expense	(20,116)	(18,828)
Loss on deconsolidation of Elevation Midstream, LLC	(73,139)	—
Income (Loss) Before Income Taxes	$ 11,237	$ (123,032)

Financial information of the Company's reportable segments was as follows for the three months ended March 31, 2020 and 2019 (in thousands).

	For the Three Months Ended March 31, 2020			
	Exploration and Production	Gathering and Facilities	Elimination of Intersegment Transactions	Consolidated Total
Revenues:				
Revenues from third parties	$ 163,714	$ 1,473	$ —	$ 165,187
Revenues from Extraction	—	4,513	(4,513)	—
Total Revenues	$ 163,714	$ 5,986	$ (4,513)	$ 165,187
Operating Expenses and Other Income (Expense):				
Direct operating expenses	$ (70,924)	$ (3,935)	$ 4,294	$ (70,565)
Depletion, depreciation, amortization and accretion	(74,952)	(1,099)	—	(76,051)
Interest income	61	29	—	90
Interest expense	(21,358)	—	—	(21,358)
Earnings in unconsolidated subsidiaries	—	480	—	480
Subtotal Operating Expenses and Other Income (Expense):	$ (167,173)	$ (4,525)	$ 4,294	$ (167,404)
Segment Assets	$ 2,703,388	$ —	$ —	$ 2,703,388
Capital Expenditures	155,441	(6,311)	—	149,130
Investment in Equity Method Investees	—	—	—	—
Segment EBITDAX	122,639	1,256	—	123,895

	For the Three Months Ended March 31, 2019			
	Exploration and Production	Gathering and Facilities	Elimination of Intersegment Transactions	Consolidated Total
Revenues:				
Revenues from third parties	$ 221,917	$ —	$ —	$ 221,917
Revenues from Extraction	—	—	—	—
Total Revenues	$ 221,917	$ —	$ —	$ 221,917
Operating Expenses and Other Income (Expense):				
Direct operating expenses	$ —	$ —	$ —	$ —
Depletion, depreciation, amortization and accretion	(118,751)	(19)	—	(118,770)
Interest income	154	625	—	779
Interest expense	(13,008)	—	—	(13,008)
Earnings in unconsolidated subsidiaries	—	338	—	338
Subtotal Operating Expenses and Other Income (Expense):	$ (131,605)	$ 944	$ —	$ (130,661)
Segment Assets	$ 3,813,513	$ 284,200	$ (714)	$ 4,096,999
Capital Expenditures	158,622	58,863	—	217,485
Investment in Equity Method Investees	—	17,555	—	17,555
Segment EBITDAX	138,339	(152)	—	138,187

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q ("Quarterly Report") contains "forward-looking statements." All statements, other than statements of historical facts, included or incorporated by reference herein concerning, among other things, planned capital expenditures, increases in oil and gas production, the number of anticipated wells to be drilled or completed after the date hereof, future cash flows and borrowings, pursuit of potential acquisition opportunities, our financial position, business strategy and other plans and objectives for future operations, are forward-looking statements. These forward-looking statements are identified by their use of terms and phrases such as "may," "expect," "estimate," "project," "plan," "believe," "intend," "achievable," "anticipate," "will," "continue," "potential," "should," "could," and similar terms and phrases. For such statements, we claim the protection of the safe harbor for forward-looking statements contained in the Private Securities Litigation Reform Act of 1995. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. Our results could differ materially from those anticipated in these forward-looking statements as a result of certain factors, including, among others:

- our ability to meet the financial covenants in our debt agreements and continue as a going concern;
- the success of our ongoing efforts to develop and implement a restructuring of our capital structure;
- federal and state regulations and laws;
- capital requirements and uncertainty of obtaining additional funding on terms acceptable to us;
- risks and restrictions related to our debt agreements;
- our ability to use derivative instruments to manage commodity price risk;
- realized oil, natural gas and NGL prices;
- a decline in oil, natural gas and NGL production, and the impact of general economic conditions on the demand for oil, natural gas and NGL and the availability of capital to oil and natural gas producers;
- asset impairments from commodity price declines;
- the outbreak of communicable diseases such as coronavirus;
- the willingness of the Organization of Petroleum Exporting Countries ("OPEC") and certain other oil and natural gas producing countries to set and maintain production levels;
- unsuccessful drilling and completion activities and the possibility of resulting write-downs;
- geographical concentration of our operations;
- constraints in the DJ Basin of Colorado with respect to gathering, transportation and processing facilities and marketing;
- lack of U.S. domestic storage;
- our ability to meet our proposed drilling schedule and to successfully drill wells that produce oil or natural gas in commercially viable quantities;
- shortages of oilfield equipment, supplies, services and qualified personnel and increased costs for such equipment, supplies, services and personnel;
- adverse variations from estimates of reserves, production, production prices and expenditure requirements, and our inability to replace our reserves through exploration and development activities;
- incorrect estimates associated with properties we acquire relating to estimated proved reserves, the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs of such acquired properties;

- drilling operations associated with the employment of horizontal drilling techniques, and adverse weather and environmental conditions;
- limited control over non-operated properties;
- title defects to our properties and inability to retain our leases;
- our ability to successfully develop our large inventory of undeveloped operated and non-operated acreage;
- our ability to retain key members of our senior management and key technical employees;
- risks relating to managing our growth, particularly in connection with the integration of significant acquisitions;
- impact of environmental, health and safety, and other governmental regulations, and of current or pending legislation;
- risks associated with a material weakness in our internal control over financial reporting;
- changes in tax laws;
- effects of competition; and
- seasonal weather conditions.

Reserve engineering is a process of estimating underground accumulations of oil, natural gas, and NGL that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers and management. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of oil, natural gas and NGL that are ultimately recovered.

In addition to the other information and risk factors set forth in this Quarterly Report, you should carefully consider the risk factors and other cautionary statements described under the heading “Risk Factors” included in our Annual Report on Form 10-K for the year ended December 31, 2019 (our “Annual Report”) and in our other filings with the Securities and Exchange Commission, which could materially affect our business, financial condition or future results. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition or future results. Other than as set forth in this Quarterly Report, there have been no material changes in our risk factors from those described in our Annual Report.

All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements in this section and elsewhere in this Quarterly Report. Except as required by law, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

Management’s Discussion and Analysis of Financial Condition and Results of Operations (“MD&A”) is intended to provide the reader of the financial statements with a narrative from the perspective of management on the financial condition, results of operations, liquidity and certain other factors that may affect the Company’s operating results. MD&A should be read in conjunction with the Condensed Consolidated Financial Statements and related Notes included in Part I, Item 1 of this Quarterly Report. The following information updates the discussion of the Company’s financial condition provided in our Annual Report and analyzes the changes in the results of operations between the three months ended March 31, 2020 and 2019.

EXECUTIVE SUMMARY

We are an independent oil and gas company focused on the acquisition, development and production of oil, natural gas and NGL reserves, as well as the construction and support of midstream assets to gather and process crude oil and gas production in the Rocky Mountain region, primarily in the Wattenberg Field of the Denver-Julesburg Basin of Colorado. We have developed an oil, natural gas and NGL asset base of proved reserves, as well as a portfolio of development drilling opportunities on high resource-potential leasehold on contiguous acreage blocks in some of the

most productive areas of what we consider to be the core of the DJ Basin. We are focused on improving cash flow and our liquidity while reducing debt.

Financial Results

For the three months ended March 31, 2020, crude oil, natural gas and NGL sales, coupled with the impact of settled derivatives, increased to $204.5 million as compared to $202.0 million in the same prior year period due to an increase in sales volumes of approximately 1,341 MBoe, partially offset by a decrease of $4.25 in realized price per BOE, including settled derivatives.

For the three months ended March 31, 2020, we had net income of $9.0 million as compared to a net loss of $94.0 million for the three months ended March 31, 2019. The change to net income for the three months ended March 31, 2020 from net loss for the three months ended March 31, 2019 was primarily driven by an increase in commodity derivative gain of $385.1 million, partially offset by an increase in operating expenses of $112.0 million and a decrease in sales revenue of $56.7 million.

Adjusted EBITDAX was $123.9 million for the three months ended March 31, 2020 as compared to $138.2 million for the three months ended March 31, 2019, reflecting a 10.3% decrease. Adjusted EBITDAX is a non-GAAP financial measure. For a definition of Adjusted EBITDAX and a reconciliation to our most directly comparable financial measure calculated and presented in accordance with GAAP, please read "—Adjusted EBITDAX."

Operational Results

During the three months ended March 31, 2020, we focused on improving free cash flow and implemented operational efficiencies to reduce drilling and completion costs. We incurred approximately $146.6 million in drilling 34 gross (24.5 net) wells with an average lateral length of 2.3 miles and completing 28 gross (22.7 net) wells with an average lateral length of 2.3 miles, all of which were horizontal wells in the DJ Basin. In addition, we incurred approximately $8.8 million of leasehold and surface acreage additions.

Recent Developments

COVID-19 Outbreak and Global Industry Downturn

The recent worldwide outbreak in several countries, including the United States, of a highly transmissible and pathogenic coronavirus ("COVID-19") and the uncertainty regarding the impact of COVID-19 and various governmental actions taken to mitigate the impact of COVID-19 have resulted in an unprecedented decline in demand for oil and natural gas. At the same time, the decision by Saudi Arabia in March 2020 to drastically reduce export prices and increase oil production followed by curtailment agreements among OPEC and other countries such as Russia further increased uncertainty and volatility around global oil supply-demand dynamics. Decreased demand from much of the United States being on lockdown to prevent the spread of COVID-19 caused domestic storage capacity to begin to fill up during March and April causing further price declines and ultimately causing oil prices to plummet. We expect the excess supply of oil and natural gas in the United States to continue for a sustained period.

The COVID-19 outbreak and its development into a pandemic in March 2020 have required that we take precautionary measures intended to help minimize the risk to our business, employees, customers, suppliers and the communities in which we operate. Our operational employees are currently still able to work on site. However, we have taken various precautionary measures with respect to such operational employees such as requiring them to verify they have not experienced any symptoms consistent with COVID-19, or been in close contact with someone showing such symptoms, before reporting to the work site, quarantining any operational employees who have shown signs of COVID-19 (regardless of whether such employee has been confirmed to be infected) and imposing social distancing requirements on work sites, all in accordance with the guidelines released by the Center for Disease Control. In addition, most of our non-operational employees are now working remotely. We have not yet experienced any material operational disruptions (including disruptions from our suppliers and service providers) as a result of the COVID-19 outbreak, nor have we had any confirmed cases of COVID-19 on any of our work sites.

Due to the decline in crude oil prices and ongoing uncertainty regarding the oil supply-demand macro environment, we have recently reduced our operations in order to preserve capital. Specifically, we have renegotiated the terms of our drilling rig contracts as discussed in *Note 13—Commitments and Contingencies* in Part I, Item 1. Financial Information of this Quarterly Report.

In addition, given the weakness in realized oil prices, we are actively evaluating whether to voluntarily curtail or shut-in a substantial portion of our current production volumes and will continue to evaluate such a measure on a regular basis in response to market conditions and contractual obligations. As substantially all of our revenues are generated by the production and sale of hydrocarbons, the curtailment or shut-in of our production could adversely affect our business, financial condition, results of operations, liquidity, and ability to finance planned capital expenditures.

Please also see Part II, Item 1A in our Annual Report and in this Quarterly Report for further information related to these matters.

Deconsolidation of Elevation Midstream, LLC

Please see *Note 1—Business and Organization* in Part I, Item 1. Financial Information of this Quarterly Report for information related to the deconsolidation of Elevation Midstream, LLC.

Reduction in Workforce

We recorded involuntary termination charges of $5.8 million in the first quarter of 2020 primarily related to one-time involuntary termination benefits, office closure and relocation benefits communicated to our workforce in February 2020. This plan was initiated to align the size and composition of our workforce with our expected future operating and capital plans.

February 2020 Divestiture

In February 2020, we completed the sale of certain non-operated producing properties for aggregate sales proceeds of approximately $12.2 million, subject to customary purchase price adjustments. No gain or loss was recognized for the February 2020 Divestiture. We continue to explore divestitures as part of our ongoing initiative to divest non-strategic assets.

Elevation Common Units

On May 1, 2020, Elevation's board of managers issued 1,530,000,000 common units at a price of $0.01 per unit to certain of Elevation's members other than Extraction (the "Capital Raise"). The Capital Raise caused our ownership of Elevation to be diluted to less than 0.01%. As a result of the Capital Raise, beginning in May 2020 Extraction will account for Elevation under the cost method of accounting. We reserve all rights related to actions taken by Elevation’s board of managers.

Midstream Projects

Primarily due to the significant decrease in oil and gas prices during March 2020, Elevation postponed indefinitely further development of gathering systems and facilities that were to be constructed to service our acreage in Hawkeye and another project in the Southwest Wattenberg area.

Senate Bill 19-181 "Protect Public Welfare Oil and Gas Operations"

In April 2019, Senate Bill 19-181 ("SB181") became law, increasing the regulatory authority of local governments in Colorado over the surface impacts of oil and gas development in a reasonable manner, and in December 2019, Colorado's Air Quality Control Commission ("AQCC") adopted new rules targeting air emissions from upstream oil and gas operation. Among other things, SB181 (i) repeals a prior law restricting local government land use authority over oil and gas mineral extraction areas to areas designated by the COGCC, (ii) directs the AQCC to review its leak detection and repair rules and to adopt rules to minimize emissions of certain air pollutants, (iii) clarifies that local governments have authority to regulate the siting of oil and gas locations in a reasonable manner, including the ability to inspect oil and gas facilities, impose fines for leaks, spills, and emissions, and impose fees on operators or owners to cover regulation and enforcement costs, (iv) allows local governments or oil and gas operators to request a technical review board to evaluate the effect of the local government's preliminary or final determination on the operator's application, (v) repeals an exemption for oil and gas production from counties' authority to regulate noise, (vi) alters forced pooling requirements by increasing the threshold to compel non-consenting individuals into statutory pooling agreements and (vii) elevates the protection of public health, safety, and welfare, the environment, and wildlife resources in the regulation of oil and gas development. Although industry trade associations opposed SB181, management believes that Extraction can continue to successfully operate our business. However, the enactment of SB181 and the development and implementation of related rules and regulations, which is under way, could lead to delays and additional costs to our business. For example, COGCC rulemaking on flowline safety (completed on November 21, 2019) and the Colorado AQCC and Air Pollution Control Division ("APCD") rulemaking on air quality standards (completed December 20, 2019) – both pursuant to SB181 – could lead to such delays or costs. Certain interest groups in Colorado opposed to oil and natural gas development generally, and hydraulic fracturing in particular, have advanced various alternatives for ballot initiatives which would result in significantly limiting or preventing oil and natural gas development in the state. Proponents of such initiatives have begun the process of attempting to qualify several initiatives to appear on the ballot in November 2020.

Going Concern

Please see *Note 4—Going Concern* in Part I, Item 1. Financial Information and "Risk Factors" in Part II, Item 1A of this Quarterly Report, as well as "—Liquidity and Capital Resources" below.

How We Evaluate Our Operations

We use a variety of financial and operational metrics to assess the performance of our oil and gas operations, including:

- Sources of revenue;
- Sales volumes;
- Realized prices on the sale of oil, natural gas and NGL, including the effect of our commodity derivative contracts;
- Lease operating expenses ("LOE");
- Capital expenditures;
- Adjusted EBITDAX (a Non-GAAP measure); and
- Free cash flow (a Non-GAAP measure).

Sources of Revenues

Our revenues are derived from the sale of our oil and natural gas production, as well as the sale of NGLs that are extracted from our natural gas during processing. Our oil, natural gas and NGL revenues do not include the effects of derivatives. For the three months ended March 31, 2020, our revenues were derived 75% from oil sales, 14% from natural gas sales and 11% from NGL sales. For the three months ended March 31, 2019, our revenues were derived 75% from oil sales, 16% from natural gas sales and 9% from NGL sales. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

Sales Volumes

The following table presents historical sales volumes for the periods indicated:

	For the Three Months Ended March 31,	
	2020	**2019**
Oil (MBbl)	3,504	3,583
Natural gas (MMcf)	19,003	13,959
NGL (MBbl)	1,906	1,327
Total (MBoe)	8,576	7,236
Average net sales (BOE/d)	94,247	80,401

As reservoir pressures decline, production from a given well or formation decreases. Growth in our future production and reserves will depend on our ability to continue to add or develop proved reserves in excess of our production. Our ability to add reserves through development projects and acquisitions is dependent on many factors, including takeaway capacity in our areas of operation and our ability to raise capital, obtain regulatory approvals, procure contract drilling rigs and personnel and successfully identify and consummate acquisitions. Please read “Risks Related to the Oil, Natural Gas and NGL Industry and Our Business” in Item 1A. of our Annual Report for a further description of the risks that affect us.

Realized Prices on the Sale of Oil, Natural Gas and NGL

Our results of operations depend upon many factors, particularly the price of oil, natural gas and NGL and our ability to market our production effectively. Oil, natural gas and NGL prices are among the most volatile of all commodity prices. For example, during the period from January 1, 2014 to March 31, 2020, NYMEX West Texas Intermediate oil prices ranged from a high of $107.26 per Bbl to a low of $20.09 per Bbl. Average daily prices for NYMEX Henry Hub gas ranged from a high of $6.15 per MMBtu to a low of $1.60 per MMBtu during the same period. Declines in, and continued depression of, the price of oil and natural gas occurring during 2015, 2019 and 2020 are due to a combination of factors including increased U.S. supply, global economic concerns stemming from COVID-19 and the price war between Russia and Saudi Arabia. These price variations can have a material impact on our financial results and capital expenditures.

Oil pricing is predominantly driven by the physical market, supply and demand, financial markets and national and international politics. The NYMEX WTI futures price is a widely used benchmark in the pricing of domestic and imported oil in the United States. The actual prices realized from the sale of oil differ from the quoted NYMEX WTI price as a result of quality and location differentials. In the DJ Basin, oil is sold under various purchase contracts with monthly pricing provisions based on NYMEX pricing, adjusted for differentials.

Natural gas prices vary by region and locality, depending upon the distance to markets, availability of pipeline capacity and supply and demand relationships in that region or locality. The NYMEX Henry Hub price of natural gas is a widely used benchmark for the pricing of natural gas in the United States. Similar to oil, the actual prices realized from the sale of natural gas differ from the quoted NYMEX Henry Hub price as a result of quality and location differentials. For example, wet natural gas with a high Btu content sells at a premium to low Btu content dry natural gas because it yields a greater quantity of NGL. Location differentials to NYMEX Henry Hub prices result from variances in transportation costs based on the natural gas’ proximity to the major consuming markets to which it is ultimately delivered. Also affecting the differential is the processing fee deduction retained by the natural gas processing plant, generally in the form of percentage of proceeds. The price we receive for our natural gas produced in the DJ Basin is based on CIG prices, adjusted for certain deductions.

Our price for NGL produced in the DJ Basin is based on a combination of prices from the Conway hub in Kansas and Mont Belvieu in Texas where this production is marketed.

The following table provides the high and low prices for NYMEX WTI and NYMEX Henry Hub prompt month contract prices and our differential to the average of those benchmark prices for the periods indicated. The differential varies, but our oil, natural gas and NGL normally sells at a discount to the NYMEX WTI and NYMEX Henry Hub price, as applicable.

	For the Three Months Ended March 31,	
	2020	2019
Oil		
NYMEX WTI High ($/Bbl)	$ 63.27	$ 60.14
NYMEX WTI Low ($/Bbl)	$ 20.09	$ 46.54
NYMEX WTI Average ($/Bbl)	$ 45.78	$ 54.90
Average Realized Price ($/Bbl)[1]	$ 35.45	$ 46.17
Average Realized Price, with derivative settlements ($/Bbl)[1]	$ 45.50	$ 41.89
Average Realized Price as a % of Average NYMEX WTI	77.4 %	84.1 %
Differential ($/Bbl) to Average NYMEX WTI[2]	$ (7.91)	$ (8.73)
Natural Gas		
NYMEX Henry Hub High ($/MMBtu)	$ 2.20	$ 3.59
NYMEX Henry Hub Low ($/MMBtu)	$ 1.60	$ 2.55
NYMEX Henry Hub Average ($/MMBtu)	$ 1.87	$ 2.87
NYMEX Henry Hub Average converted to a $/Mcf basis[3]	$ 2.06	$ 3.16
Average Realized Price ($/Mcf)	$ 1.17	$ 2.57
Average Realized Price, with derivative settlements ($/Mcf)	$ 1.39	$ 2.25
Average Realized Price as a % of Average NYMEX Henry Hub[3]	56.8 %	81.3 %
Differential ($/Mcf) to Average NYMEX Henry Hub[3]	$ (0.89)	$ (0.59)
NGL		
Average Realized Price ($/Bbl)[4]	$ 9.02	$ 15.53
Average Realized Price as a % of Average NYMEX WTI	19.7 %	28.3 %
BOE		
Average Realized Price per BOE	$ 19.09	$ 30.67
Average Realized Price per BOE with derivative settlements	$ 23.67	$ 27.92

(1) Includes non-cash amounts allocated to a satisfied performance obligation, recognized within oil sales for the three months ended March 31, 2020, pursuant to ASC 606, Revenue Recognition.
(2) Excludes non-cash amounts allocated to a satisfied performance obligation, recognized within oil sales for the three months ended March 31, 2020, pursuant to ASC 606, Revenue Recognition.
(3) Based on the difference between our average realized price and the NYMEX Henry Hub Average as converted into Mcf using a conversion factor of 1.1 to 1.
(4) The decrease year over year is primarily due to capacity constraints in transporting the wet gas associated with our production coupled with negative market conditions surrounding limited export capacity.

Derivative Arrangements

To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in commodity prices, from time to time, we enter into derivative arrangements for our oil and natural gas production. By removing a significant portion of price volatility associated with our oil and natural gas production, we believe we will mitigate, but not eliminate, the potential negative effects of reductions in oil and natural gas prices on our cash flow from operations for those periods. However, in a portion of our current positions, our hedging activity may also reduce our ability to benefit from increases in oil and natural gas prices. We will sustain losses to the extent our derivatives contract prices are lower than market prices and, conversely, we will realize gains to the extent our derivatives contract prices are higher than market prices. In certain circumstances, where we have unrealized gains in our derivative portfolio, we may choose to restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of our existing positions. See "—Quantitative and Qualitative Disclosure About Market

Risk—Commodity Price Risk" for information regarding our exposure to market risk, including the effects of changes in commodity prices, and our commodity derivative contracts.

We will continue to use commodity derivative instruments to hedge our price risk in the future. Our hedging strategy and future hedging transactions will be determined at our discretion and may be different than what we have done on a historical basis. As a result of recent volatility in the price of oil and natural gas, we have relied on a variety of hedging strategies and instruments to hedge our future price risk. We have utilized swaps, put options and call options, which in some instances require the payment of a premium, to reduce the effect of price changes on a portion of our future oil and natural gas production. We expect to continue to use a variety of hedging strategies and instruments for the foreseeable future.

A swap has an established fixed price. When the settlement price is below the fixed price, the counterparty pays us an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume. When the settlement price is above the fixed price, we pay our counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume.

A put option has an established floor price. The buyer of the put option pays the seller a premium to enter into the put option. When the settlement price is below the floor price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is above the floor price, the put option expires worthless. Some of our purchased put options have deferred premiums. For the deferred premium puts, we agreed to pay a premium to the counterparty at the time of settlement.

A call option has an established ceiling price. The buyer of the call option pays the seller a premium to enter into the call option. When the settlement price is above the ceiling price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is below the ceiling price, the call option expires worthless.

We combine swaps, purchased put options, sold put options, and sold call options in order to achieve various hedging strategies. Some examples of our hedging strategies are collars which include purchased put options and sold call options, three-way collars which include purchased put options, sold put options, and sold call options, and enhanced swaps, which include either sold put options or sold call options with the associated premiums rolled into an enhanced fixed price swap. We have historically relied on commodity derivative contracts to mitigate our exposure to lower commodity prices.

We have historically been able to hedge our oil and natural gas production at prices that are significantly higher than current strip prices. However, in the current commodity price environment, our ability to enter into comparable derivative arrangements at favorable prices may be limited, and, we are not obligated to hedge a specific portion of our oil or natural gas production.

For a description of our derivative instruments that we utilize and a summary of our commodity derivative contracts as of March 31, 2020, please see *Note 6—Commodity Derivative Instruments* in Part I, Item 1. Financial Information of this Quarterly Report.

The following table summarizes our historical derivative positions and the settlement amounts for each of the periods indicated.

	For the Three Months Ended March 31,	
	2020	**2019**
NYMEX WTI Crude Swaps:		
Notional volume (Bbl)	225,000	1,350,000
Weighted average fixed price ($/Bbl)	$ 60.13	$ 54.58
NYMEX WTI Crude Purchased Puts:		
Notional volume (Bbl)	3,650,000	4,725,000
Weighted average purchased put price ($/Bbl)	$ 54.79	$ 46.05
NYMEX WTI Crude Purchased Calls:		
Notional volume (Bbl)	600,000	5,100,000
Weighted average purchased call price ($/Bbl)	$ 68.05	$ 63.40
NYMEX WTI Crude Sold Calls:		
Notional volume (Bbl)	3,650,000	6,600,000

Weighted average sold call price ($/Bbl)	$	63.34	$	62.17
NYMEX WTI Crude Sold Puts:				
Notional volume (Bbl)		3,700,000		4,200,000
Weighted average sold put price ($/Bbl)	$	44.01	$	43.35
NYMEX HH Natural Gas Swaps:				
Notional volume (MMBtu)		8,400,000		5,400,000
Weighted average fixed price ($/MMBtu)	$	2.76	$	3.11
NYMEX HH Natural Gas Purchased Puts:				
Notional volume (MMBtu)		600,000		3,600,000
Weighted average purchased put price ($/MMBtu)	$	2.90	$	3.04
NYMEX HH Natural Gas Sold Calls:				
Notional volume (MMBtu)		600,000		3,600,000
Weighted average sold call price ($/MMBtu)	$	3.48	$	3.46
NYMEX HH Natural Gas Sold Puts:				
Notional volume (MMBtu)		—		3,000,000
Weighted average sold put price ($/MMBtu)	$	—	$	2.50
CIG Basis Gas Swaps:				
Notional volume (MMBtu)		11,400,000		9,400,000
Weighted average fixed basis price ($/MMBtu)	$	(0.61)	$	(0.75)
Total Amounts Received/(Paid) from Settlement (in thousands)	$	39,295	$	(10,329)
Cash provided by changes in Accounts Receivable and Accounts Payable related to Commodity Derivatives	$	(14,363)	$	6,791
Cash Settlements on Commodity Derivatives per Condensed Consolidated Statements of Cash Flows	$	24,932	$	(3,538)

Lease Operating Expenses

All direct and allocated indirect costs of lifting hydrocarbons from a producing formation to the surface constitutes part of the current operating expenses of a working interest. Such costs include labor, superintendence, supplies, repairs, maintenance, water injection and disposal costs, allocated overhead charges, workover, insurance and other expenses incidental to production, but exclude lease acquisition or drilling or completion expenses.

Capital Expenditures

For the three months ended March 31, 2020, we incurred approximately $146.6 million in drilling and completion capital expenditures. For the three months ended March 31, 2020, we drilled 34 gross (24.5 net) wells with an average lateral length of approximately 2.3 miles and completed 28 gross (22.7 net) wells with an average lateral length of approximately 2.3 miles. We turned to sales 13 gross (12 net) wells with an average lateral length of approximately 2.1 miles. In addition, we incurred approximately $8.8 million of leasehold and surface acreage additions.

The amount and timing of these capital expenditures is within our control and subject to our management's discretion. We retain the flexibility to defer a portion of these planned capital expenditures depending on a variety of factors, including but not limited to the success of our drilling activities, prevailing and anticipated prices for oil, natural gas and NGL, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other interest owners. Any postponement or elimination of our development drilling program could result in a reduction of proved reserve volumes and related standardized measure. These risks could materially affect our business, financial condition and results of operations.

Adjusted EBITDAX

Adjusted EBITDAX is not a measure of net income (loss) as determined by United States GAAP. Adjusted EBITDAX is a supplemental non-GAAP financial measure that is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We define Adjusted EBITDAX as net income (loss) adjusted for certain cash and non-cash items, including depletion, depreciation, amortization and

accretion (DD&A), impairment of long lived assets, non-recurring charges in other operating expenses, exploration and abandonment expenses, gain on sale of property and equipment, (gain) loss on commodity derivatives, settlements on commodity derivative instruments, premiums paid for derivatives that settled during the period, stock-based compensation expense, amortization of debt issuance costs, gain on repurchase of senior notes, interest expense, income tax expense (benefit) and loss on deconsolidation of Elevation Midstream, LLC. Adjusted EBITDAX is also used to evaluate the performance of reportable segments. Please see *Note 15—Segment Information* in Part I, Item 1. Financial Information of this Quarterly Report for more information regarding the EBITDAX of reportable segments.

Management believes Adjusted EBITDAX is useful because it allows us to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income (loss) in arriving at Adjusted EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDAX should not be considered as an alternative to, or more meaningful than, net income (loss) as determined in accordance with GAAP or as an indicator of our operating performance. Certain items excluded from Adjusted EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital, hedging strategy and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDAX. Our computations of Adjusted EBITDAX may not be comparable to other similarly titled measure of other companies. We believe that Adjusted EBITDAX is a widely followed measure of operating performance. Additionally, our management team believes Adjusted EBITDAX is useful to an investor in evaluating our financial performance because this measure (i) is widely used by investors in the oil and natural gas industry to measure a company's operating performance without regard to items excluded from the calculation of such term, among other factors; (ii) helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and (iii) is used by our management team for various purposes, including as a measure of operating performance, in presentations to our board of directors, as a basis for strategic planning and forecasting.

The following table presents a reconciliation of Adjusted EBITDAX to the GAAP financial measure of net income (loss) for each of the periods indicated (in thousands).

	For the Three Months Ended March 31,	
	2020	2019
Reconciliation of Net Income (Loss) to Adjusted EBITDAX:		
Net income (loss)	$ 9,037	$ (94,032)
Add back:		
Depletion, depreciation, amortization and accretion	76,051	118,770
Impairment of long lived assets	775	8,248
Other operating expenses	52,575	—
Exploration and abandonment expenses	112,480	6,194
Gain on sale of property and equipment	—	(222)
(Gain) loss on commodity derivatives	(263,015)	122,091
Settlements on commodity derivative instruments	39,295	(10,329)
Premiums paid for derivatives that settled during the period	—	(9,549)
Stock-based compensation expense	—	13,008
Amortization of debt issuance costs	1,242	1,497
Gain on repurchase of 2026 Senior Notes	—	(7,317)
Interest expense	20,116	18,828
Income tax expense (benefit)	2,200	(29,000)
Loss on deconsolidation of Elevation Midstream, LLC	73,139	—
Adjusted EBITDAX	$ 123,895	$ 138,187

Free Cash Flow

Our Free Cash Flow is not a measure of net income (loss) as determined by GAAP. We define Free Cash Flow as Discretionary Cash Flow (non-GAAP) less Adjusted Cash Flow used in Investing (non-GAAP) adjusted for Other Non-Recurring Adjustments (non-GAAP). Discretionary Cash Flow is defined as net cash provided by operating activities (GAAP) less changes in working capital (current assets and liabilities). Adjusted Cash Flow used in Investing is defined as cash flow used in investing activities (GAAP) adjusted for changes in accounts payable and accrued liabilities related to capital expenditures.

Free Cash Flow is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We believe Free Cash Flow can provide additional transparency into the drivers of trends in our operating cash flows, such as production, realized sales prices and operating costs, as it disregards the timing of settlement of operating assets and liabilities. We believe Free Cash Flow provides additional information that may be useful in an analysis of our ability to generate cash to fund exploration and development activities, construct and support midstream assets, and to return capital to stockholders.

The following tables present a reconciliation of Discretionary Cash Flow and Free Cash Flow to the GAAP financial measure of net cash provided by operating activities for each of the periods indicated.

	Upstream	Midstream	Consolidated
	For the Three Months Ended March 31, 2020		
Cash Flow from Operating Activities			
Net cash provided by operating activities	$ 144,219	$ 2,880	$ 147,099
Changes in current assets and liabilities	(101,047)	(1,907)	(102,954)
Discretionary Cash Flow	43,172	973	44,145
Cash Flow from Investing Activities			
Net cash used in investing activities	(133,863)	(5,840)	(139,703)
Change in accounts payable and accrued liabilities related to capital expenditures	(10,477)	2,210	(8,267)
Adjusted Cash Flow used in Investing	(144,340)	(3,630)	(147,970)
Other Non-Recurring Adjustments[1]	1,170	—	1,170
Free Cash Flow	$ (99,998)	$ (2,657)	$ (102,655)

	Upstream	Midstream	Consolidated
	For the Three Months Ended March 31, 2019		
Cash Flow from Operating Activities			
Net cash provided by operating activities	$ 131,121	$ 2,990	$ 134,111
Changes in current assets and liabilities	3,634	(447)	3,187
Discretionary Cash Flow	134,755	2,543	137,298
Cash Flow from Investing Activities			
Net cash used in investing activities	(184,719)	(47,656)	(232,375)
Change in accounts payable and accrued liabilities related to capital expenditures	8,350	(9,566)	(1,216)
Adjusted Cash Flow used in Investing	(176,369)	(57,222)	(233,591)
Other Non-Recurring Adjustments[1]	1,582	—	1,582
Free Cash Flow	$ (40,032)	$ (54,679)	$ (94,711)

(1) Amount incurred for the construction of our field office that is included in other property and equipment in our condensed consolidated statements of cash flows.

Items Affecting the Comparability of Our Financial Results

Our historical results of operations for the periods presented may not be comparable, either to each other or to our future results of operations, for the reasons described below:

- For the three months ended March 31, 2020 and 2019, respectively, exploration and abandonment expenses increased primarily due to the abandonment of $106.9 million and $3.9 million of unproved properties.
- Elevation Midstream, LLC was deconsolidated as of March 16, 2020 and accounted for as an equity method investment. We elected the fair value option to remeasure the Elevation Midstream, LLC equity method investment and determined it had no fair value. We recorded a $73.1 million loss on deconsolidation of Elevation Midstream, LLC in the condensed consolidated statements of operations for the three months ended March 31, 2020. Please see *Note 1—Business and Organization* in Part I, Item 1. Financial Information of this Quarterly Report for information related to the deconsolidation of Elevation Midstream, LLC.
- On April 2, 2020, Elevation demanded payment of $46.8 million due to an alleged breach in contract stemming from a purported failure to complete the pipeline extensions connecting certain wells to the Badger central gathering facility prior to April 1, 2020. While the Company disputes that these amounts are due to Elevation, under ASC *Topic 450 - Contingencies*, we recorded the amount in other operating expenses on the condensed consolidated statements of operations for the three months ended March 31, 2020.

Historical Results of Operations and Operating Expenses

Oil, Natural Gas and NGL Sales Revenues, Operating Expenses and Other Income (Expense).

For components of our revenues, operating expenses, other income (expense) and net income (loss), please see our condensed consolidated statements of operations in Part I, Item 1. Financial Information of this Quarterly Report.

The following table provides a summary of our sales volumes, average prices and operating expenses on a per BOE basis for the periods indicated:

	For the Three Months Ended March 31,	
	2020	**2019**
Sales (MBoe)[1]:	8,576	7,236
Oil sales (MBbl)	3,504	3,583
Natural gas sales (MMcf)	19,003	13,959
NGL sales (MBbl)	1,906	1,327
Sales (BOE/d)[1]:	94,247	80,401
Oil sales (Bbl/d)	38,502	39,809
Natural gas sales (Mcf/d)	208,819	155,103
NGL sales (Bbl/d)	20,942	14,742
Average sales prices[2]:		
Oil sales (per Bbl)[3]	$ 35.45	$ 46.17
Oil sales with derivative settlements (per Bbl)[3]	45.50	41.89
Natural gas sales (per Mcf)	1.17	2.57
Natural gas sales with derivative settlements (per Mcf)	1.39	2.25
NGL sales (per Bbl)	9.02	15.53
Average price (per BOE)[3]	19.09	30.67
Average price with derivative settlements (per BOE)[3]	23.67	27.92
Expense per BOE:		
Lease operating expenses	$ 3.54	$ 3.02
Transportation and gathering	2.66	1.43
Production taxes	1.57	2.51
Exploration and abandonment expenses	13.11	0.86
Depletion, depreciation, amortization and accretion	8.87	16.41
General and administrative expenses	1.24	3.82
Cash general and administrative expenses[4]	1.24	2.02
Stock-based compensation	—	1.80
Total operating expenses per BOE[5]	$ 30.99	$ 28.05
Production taxes as a percentage of revenue	8.1 %	8.2 %

(1) One BOE is equal to six Mcf of natural gas or one Bbl of oil or NGL based on an approximate energy equivalency. This is an energy content correlation and does not reflect a value or price relationship between the commodities.

(2) Average prices shown in the table reflect prices both before and after the effects of our settlements of commodity derivative contracts. Our calculation of such effects includes both gains and losses on settlements for commodity derivatives and amortization of premiums paid or received on options that settled during the period.

(3) Includes amounts allocated to a satisfied performance obligation, recognized within oil sales for the three months ended March 31, 2020, pursuant to ASC 606, Revenue Recognition.

(4) Cash general and administrative expenses for the three months ended March 31, 2020 includes expense of $2.2 million related to the terms of a separation agreement with a former executive officer. Excluding this one-time expense results in cash general and administrative expense per BOE of $0.97 for the three months ended March 31, 2020.

(5) Excludes midstream operating expenses, impairment of long lived assets, gain on sale of property and equipment, and other operating expenses.

Three Months Ended March 31, 2020 Compared to Three Months Ended March 31, 2019

Oil sales revenues. Crude oil sales revenues decreased by $41.2 million to $124.2 million for the three months ended March 31, 2020 as compared to crude oil sales of $165.4 million for the three months ended March 31, 2019. A decrease in sales volumes between these periods contributed a $3.7 million negative impact, and a decrease in crude oil prices contributed a $37.5 million negative impact. For the three months ended March 31, 2020, crude oil revenue decreased by approximately $8.5 million due to the impact of the increase in the forecasted deferral balance on one of our revenue contracts. Pursuant to ASC 606, the contract term impacts the amount of consideration that can be included in the transaction price, which reduced oil sales revenue.

For the three months ended March 31, 2020, our crude oil sales averaged 38.5 MBbl/d. Our crude oil sales volume decreased by 0.1 to 3.5 MBbl for the three months ended March 31, 2020 compared to 3.6 MBbl for the three months ended March 31, 2019. The volume decrease is primarily due to the natural decline of our existing properties, partially offset by an increase in production from the completion of 28 gross wells from January 1, 2020 to March 31, 2020.

The average price we realized on the sale of crude oil was $35.45 per Bbl for the three months ended March 31, 2020 compared to $46.17 per Bbl for the three months ended March 31, 2019, primarily due to changes in market prices for crude oil and the $8.5 million decrease of crude oil revenue explained above.

Natural gas sales revenues. Natural gas sales revenues decreased by $13.6 million to $22.3 million for the three months ended March 31, 2020 as compared to natural gas sales revenues of $35.9 million for the three months ended March 31, 2019. An increase in sales volumes between these periods contributed a $13.0 million positive impact, while a decrease in natural gas prices contributed a $26.6 million negative impact.

For the three months ended March 31, 2020, our natural gas sales averaged 208.8 MMcf/d. Natural gas sales volumes increased by 5.0 to 19.0 MMcf for the three months ended March 31, 2020 as compared to 14.0 MMcf for the three months ended March 31, 2019. The volume increase is primarily due to the completion of 28 gross wells from January 1, 2020 to March 31, 2020, partially offset by the natural decline on existing producing properties.

The average price we realized on the sale of our natural gas was $1.17 per Mcf for the three months ended March 31, 2020 compared to $2.57 per Mcf for the three months ended March 31, 2019, primarily due to capacity constraints in transporting the wet gas associated with crude oil production coupled with negative market conditions surrounding limited export capacity.

NGL sales revenues. NGL sales revenues decreased by $3.4 million to $17.2 million for the three months ended March 31, 2020 as compared to NGL sales revenues of $20.6 million for the three months ended March 31, 2019. An increase in sales volumes between these periods contributed a $8.9 million positive impact, while a decrease in price contributed a $12.3 million negative impact.

For the three months ended March 31, 2020, our NGL sales averaged 20.9 MBbl/d. NGL sales volumes increased by 0.6 to 1.9 MBbl for the three months ended March 31, 2020 as compared to 1.3 MBbl for the three months ended March 31, 2019. The volume increase is primarily due to the completion of 28 gross wells during the three months ended March 31, 2020, partially offset by the natural decline on existing producing properties. Our NGL sales are directly associated with our natural gas sales because our natural gas volumes are processed by third parties for both residue natural gas sales and NGL sales.

The average price we realized on the sale of our NGL was $9.02 per Bbl for the three months ended March 31, 2020 compared to $15.53 per Bbl for the three months ended March 31, 2019, primarily due to capacity constraints in transporting the wet gas associated with crude oil production coupled with negative market conditions surrounding limited export capacity.

Lease operating expenses. Our LOE increased by $8.5 million to $30.4 million for the three months ended March 31, 2020, from $21.9 million for the three months ended March 31, 2019. The increase in LOE was primarily the result of an increase in producing wells and an increase in workover repairs, partially offset by optimization of our field cost structure during the three months ended March 31, 2020. On a per unit basis, LOE increased to $3.54 per BOE sold for the three months ended March 31, 2020 from $3.02 per BOE for the three months ended March 31, 2019.

Transportation and gathering ("T&G"). Our T&G expense increased by $12.4 million to $22.8 million for the three months ended March 31, 2020, from $10.4 million for the three months ended March 31, 2019. The increase in T&G was primarily due to an increase of volumes on a certain gathering system during the three months ended March 31, 2020 compared to the three months ended March 31, 2019. On a per unit basis, T&G increased to $2.66 per BOE sold for the three months ended March 31, 2020 compared to $1.43 per BOE sold for the three months ended March 31, 2019.

Production taxes. Our production taxes decreased by $4.6 million to $13.5 million for the three months ended March 31, 2020 as compared to $18.1 million for the three months ended March 31, 2019. The decrease is primarily attributable to decreased revenue as production taxes are calculated as a percentage of sales revenue. Production taxes as a percentage of sales revenue was 8.1% for the three months ended March 31, 2020 as compared to 8.2% for the three months ended March 31, 2019. The consistency in production taxes as a percentage of sales revenue relates to comparatively constant estimated ad valorem and severance tax rates for the three months ended March 31, 2020.

Exploration and abandonment expenses. Our exploration and abandonment expenses were $112.5 million for the three months ended March 31, 2020, of which $106.9 million was lease abandonment expense. Due to the decrease in pricing, all of the unproved property in our northern field was abandoned and impaired. For the three months ended March 31, 2019, we recognized $6.2 million in exploration and abandonment expenses.

Depletion, depreciation, amortization and accretion expense. Our DD&A expense decreased $42.7 million to $76.1 million for the three months ended March 31, 2020 as compared to $118.8 million for the three months ended March 31, 2019. On a per unit basis, DD&A expense decreased to $8.87 per BOE for the three months ended March 31, 2020 from $16.41 per BOE for the three months ended March 31, 2019. This decrease is due to an impairment of $1.3 billion of proved oil and gas properties that occurred during the fourth quarter of 2019.

Impairment of long lived assets. For the three months ended March 31, 2020 and 2019, impairment expense was $0.8 million and $8.2 million, respectively, related to impairment of the proved oil and gas properties in our northern field as the fair value did not exceed the carrying amount associated with the properties.

General and administrative expenses ("G&A"). General and administrative expenses decreased by $17.1 million to $10.6 million for the three months ended March 31, 2020 as compared to $27.7 million for the three months ended March 31, 2019. This decrease is primarily due to a one-time reduction of workforce during the first quarter of 2020, and a decrease in stock-based compensation expense recognized for the three months ended March 31, 2020 compared to the three months ended March 31, 2019. On a per unit basis, G&A expense decreased to $1.24 per BOE sold for the three months ended March 31, 2020 from $3.82 per BOE sold for the three months ended March 31, 2019.

Our G&A expenses for the three months ended March 31, 2020 includes $2.2 million related to the terms of a separation agreement with a former executive officer. No expenses of this nature were incurred during the three months ended March 31, 2019.

Our G&A expenses include the non-cash expense for stock-based compensation for equity awards granted to our employees and directors. For the three months ended March 31, 2020, there was no stock-based compensation expense primarily as a result of a true-up related to forfeitures in connection with the workforce reduction in February 2020. For the three months ended March 31, 2019, stock-based compensation expense was $13.0 million.

Other operating expenses. Other operating expenses were $52.6 million for the three months ended March 31, 2020. This amount is primarily made up of a $46.8 million loss contingency from an alleged breach in contract stemming from a purported failure to complete the pipeline extensions connecting certain wells to the Badger central gathering

facility prior to April 1, 2020. Also included in this amount is a $5.8 million charge to income for expenses related to a workforce reduction in February 2020.

Commodity derivative gain (loss). Primarily due to the decrease in NYMEX crude oil futures prices at March 31, 2020 as compared to December 31, 2019 and change in fair value from the execution of new positions, we incurred a net gain on our commodity derivatives of $263.0 million for the three months ended March 31, 2020. Primarily due to the increase in NYMEX crude oil futures prices at March 31, 2019 as compared to December 31, 2018 and change in fair value from the execution of new positions, we incurred a net loss on our commodity derivatives of $122.1 million for the three months ended March 31, 2019, including the amortization of premiums. These gains and losses are a result of our hedging program, which is used to mitigate our exposure to commodity price fluctuations. The fair value of the open commodity derivative instruments will continue to change in value until the transactions are settled and we will likely add to our hedging program in the future. Therefore, we expect our net income (loss) to reflect the volatility of commodity price forward markets. Our cash flow will only be affected upon settlement of the transactions at the current market prices at that time. During the three months ended March 31, 2020, we received cash settlements of commodity derivatives totaling $39.3 million. During the three months ended March 31, 2019, we paid settlements of commodity derivatives totaling $10.3 million.

Loss on deconsolidation of Elevation Midstream, LLC. On March 16, 2020, we deconsolidated Elevation Midstream, LLC. Upon deconsolidation, we elected the fair value option to remeasure the Elevation equity method investment and determined it had no fair value. The Company recorded a $73.1 million loss on deconsolidation of Elevation Midstream, LLC in the condensed consolidated statements of operations for the three months ended March 31, 2020.

Interest expense. Interest expense consists of interest expense on our long-term debt and amortization of debt issuance costs, net of capitalized interest. For the three months ended March 31, 2020, we recognized interest expense of $21.4 million as compared to $13.0 million for the three months ended March 31, 2019, as a result of borrowings under our revolving credit facility, our 2024 Senior Notes, our 2026 Senior Notes and the amortization of debt issuance costs.

We incurred interest expense for the three months ended March 31, 2020 of $22.3 million related to our 2024 Senior Notes, 2026 Senior Notes, and revolving credit facility. We incurred interest expense for the three months ended March 31, 2019 of approximately $20.8 million related to our revolving credit facility, our 2024 Senior Notes, and our 2026 Senior Notes. Also included in interest expense for the three months ended March 31, 2020 and 2019 was the amortization of debt issuance costs of $1.2 million and $1.5 million, respectively. For the three months ended March 31, 2020 and 2019, we capitalized interest expense of $2.1 million and $2.0 million, respectively. Interest expense for the three months ended March 31, 2019 also includes $7.3 million of gain on debt extinguishment upon the repurchase of our 2026 Senior Notes.

Income tax (expense) benefit. We recorded an income tax expense and benefit of $2.2 million and $29.0 million, respectively, for the three months ended March 31, 2020 and 2019, respectively. This resulted in an effective tax rate of approximately 19.6% and 23.6% for the three months ended March 31, 2020 and 2019, respectively. Our effective tax rate for the three months ended March 31, 2020 and 2019 differs from the U.S. statutory income tax rates of 21.0% primarily due to the effects of state income taxes, estimated taxable permanent differences, and valuation allowance.

Gathering and facilities segment. Prior to March 31, 2020, we had two operating segments, (i) the exploration, development and production of oil, natural gas and NGL (the "exploration and production segment") and (ii) the construction, operation and support of midstream assets to gather and process crude oil and gas production (the "gathering and facilities segment"). Please see *Note 1—Business and Organization* in Part I, Item I, Financial Information of this Quarterly Report for further information related to the deconsolidation of Elevation Midstream, LLC. After March 31, 2020, Extraction will report as a single operating segment.

In October 2019, Elevation commenced moving crude oil, natural gas and water through its Badger central gathering facility. Because Elevation had no revenue and insignificant operating expenses for the three months ended March 31, 2019, comparison to the three months ended March 31, 2020 is not relevant. For the three months ending March 31, 2020, our gathering and facilities segment had revenues of $5.9 million and direct operating expenses of $3.9

million. General and administrative expenses were $1.1 million for both of the three months ended March 31, 2020 and 2019. For the three months ended March 31, 2020, depreciation expense was $1.1 million as the gathering facility was placed into service during the fourth quarter of 2019. Please see *Note 15—Segments* in Part I, Item I, Financial Information of this Quarterly Report.

Liquidity and Capital Resources

Current Financial Condition and Liquidity

The market price for oil, natural gas and NGLs decreased significantly beginning in the first quarter of 2020, continuing into the second quarter of 2020. The decrease in the market price for our production directly reduces our cash flow from operations and indirectly impacts other potential sources of funds described above. Our ability to continue as a going concern is dependent upon attaining and maintaining profitable operations and, until that time, raising additional capital as needed, but there can be no assurance that we will be able to raise sufficient financing on terms that are acceptable to us, or at all. As discussed in *Note 4—Going Concern* in Part I, Item I, Financial Information of this Quarterly Report, on April 27, 2020 the lenders under the revolving credit facility elected to reduce the borrowing base and elected commitments to $650.0 million from $950.0 million, and we borrowed all of the remaining available capacity under the revolving credit facility. As a result of the reduction of the borrowing base and elected commitments, it is probable that we will not meet the financial covenants under the revolving credit facility for the three months ended June 30, 2020 when assuming our current financial forecast.

We may seek covenant relief from the lenders under the revolving credit facility, and if we do not obtain a waiver of financial covenants for the three months ended June 30, 2020, the lenders under the revolving credit facility will be able to declare all outstanding principal and interest to be due and payable, and the lenders under the credit agreement could terminate their commitments to loan money and could foreclose against the assets collateralizing their borrowings. Any acceleration of the obligations under the revolving credit facility would result in a cross-default and potential acceleration of the maturity of our other outstanding long-term debt. These potential defaults create uncertainty associated with our ability to repay outstanding long-term debt obligations as they become due and creates a substantial doubt over our ability to continue as a going concern.

As a result of the impacts to our financial position resulting from declining commodity price conditions and in consideration of the substantial amount of long-term debt and preferred stock outstanding, we have engaged advisors to assist with the evaluation of strategic alternatives, which may include, but not be limited to, seeking a restructuring, amendment or refinancing of existing debt through a private restructuring or reorganization under Chapter 11 of the Bankruptcy Code. However, there can be no assurances that we will be able to successfully restructure our indebtedness, improve our financial position or complete any strategic transactions. As a result of these uncertainties and the likelihood of a restructuring or reorganization, management has concluded that there is substantial doubt regarding our ability to continue as a going concern.

Sources of Liquidity and Capital Resources

Historically, our primary sources of liquidity have been borrowings under our revolving credit facility, proceeds from notes offerings and preferred stock offerings, equity provided by investors, including our management team, cash from issuance of preferred stock, and cash flows from divestitures and from the sale of oil, gas and NGL production. Our primary uses of capital have been for the acquisition of oil and gas properties to increase our acreage position, as well as development and exploration of oil and gas properties. Our borrowings, net of unamortized debt issuance costs, were approximately $1,556.3 million and $1,555.8 million at March 31, 2020, and December 31, 2019, respectively. We also have other contractual commitments, which are described in *Note 13—Commitments and Contingencies* in Part I, Item 1, Financial Information of this Quarterly Report.

We may from time to time seek to retire or purchase our outstanding notes through cash purchases and/or exchanges (including for equity securities), in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

We plan to continue our practice of entering into hedging arrangements to reduce the impact of commodity price volatility on our cash flow from operations. Under this strategy, we intend to enter into commodity derivative contracts at times and on terms desired to maintain a portfolio of commodity derivative contracts covering approximately 50% to 70% of our projected oil and natural gas production over a one to two year period at a given point in time, although we may from time to time hedge more or less than this approximate range.

If cash flow from operations does not meet our expectations, we may further reduce our expected level of capital expenditures and/or fund a portion of our capital expenditures using borrowings under our revolving credit facility, issuances of debt and equity securities or from other sources, such as asset sales. We cannot assure you that necessary capital will be available on acceptable terms or at all. Our ability to raise funds through the incurrence of additional indebtedness could be limited by the covenants in our debt arrangements. If we are unable to obtain funds when needed or on acceptable terms, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to maintain our production or proved reserves.

We had a Stock Repurchase Program that ended in 2019. During the three months ended March 31, 2019. Spending under this program was $60.0 million. We also have a Senior Notes Repurchase Program in place. Spending under this program during the three months ended March 31, 2019 was $28.5 million. No Senior Notes were repurchased during the three months ended March 31, 2020. We are authorized to repurchase up to $100.0 million of our Senior Notes.

Cash Flows

The following table summarizes our cash flows for the periods indicated (in thousands):

	For the Three Months Ended March 31,	
	2020	**2019**
Net cash provided by operating activities	$ 147,099	$ 134,111
Net cash used in investing activities	$ (139,703)	$ (232,375)
Net cash used in financing activities	$ (57)	$ (23,951)

Three Months Ended March 31, 2020 Compared to Three Months Ended March 31, 2019

Net cash provided by operating activities. For the three months ended March 31, 2020 as compared to the three months ended March 31, 2019, our net cash provided by operating activities increased by $13.0 million, primarily due to an increase of $59.4 million related to changes in working capital and an increase of $28.5 million in commodity derivative settlement payments offset by a decrease in operating revenues net of expenses of $76.9 million primarily as a result of a decrease in commodity prices.

Net cash used in investing activities. For the three months ended March 31, 2020, net cash used in investing activities decreased by $92.7 million compared to the three months ended March 31, 2019 primarily as a result of $45.0 million less spent on oil and gas property additions, $53.4 million less spent on gathering systems and facilities and $5.2 million less spent on other property and equipment offset by $5.1 million more spent on our investment in unconsolidated subsidiaries. Also, the proceeds from the sale of assets were $4.4 million less during the first quarter of 2020 than during the same period in 2019.

Net cash used in financing activities. For the three months ended March 31, 2020, net cash used in financing activities was $23.9 million less than for the three months ended March 31, 2019 primarily as a result of $28.5 million spent to repurchase 2026 Senior Notes and $32.2 million spent to repurchase of common stock during the first quarter of 2019 which were not spent during first quarter of 2020. Also, net borrowings on the credit facility during the first quarter of 2019 were $40.0 million compared to none during the first quarter of 2020.

Working Capital

Our working capital deficit was $144.6 million and $240.8 million at March 31, 2020 and December 31, 2019, respectively. Our cash balances totaled $32.0 million and $32.4 million at March 31, 2020 and December 31, 2019, respectively.

Due to the amounts that we incur related to our drilling and completion program and the timing of such expenditures, we may incur working capital deficits in the future. We expect that our pace of development, production volumes, commodity prices and differentials to NYMEX prices for our oil, natural gas and NGL production will be the largest variables affecting our working capital. Due to the oil, natural gas and NGL price declines during the first and second quarter of 2020, we modified our drilling rig contracts to have minimal drilling activity for the remainder of the year. Please see *Note 13—Commitments and Contingencies* and *Note 4—Going Concern* in Part 1, Item 1. Financial Information of this Quarterly Report.

Debt Arrangements

For details of our debt arrangements including our credit facility, 2024 Senior Notes and 2026 Senior Notes, please see *Note 5—Long-Term Debt* in Part I, Item 1. Financial Information of this Quarterly Report. Additional debt disclosures specific to this *Management Discussion and Analysis* section are as follows.

If we experience certain kinds of changes of control, holders of our 2024 and 2026 Senior Notes may have the right to require us to repurchase their notes at 101% of the principal amount of the notes, plus accrued and unpaid interest, if any, to the date of purchase.

Equity Arrangements

For details of our equity arrangements including our Series A Preferred Stock and Elevation Preferred Units, please see *Note 11—Equity* in Part I, Item 1. Financial Information of this Quarterly Report.

Critical Accounting Policies and Estimates

There were no material changes to our critical accounting policies and estimates from those disclosed in our Annual Report on Form 10-K for the year ended December 31, 2019 other than the deconsolidation of Elevation Midstream, LLC discussed in *Note 1—Business and Organization* in Part I, Item 1. Financial Information of this Quarterly Report.

Recent Accounting Pronouncements

Please see *Note 2—Basis of Presentation, Significant Accounting Policies and Recent Accounting Pronouncements* in Part 1, Item 1 of this Quarterly Report for a detailed list of recent accounting pronouncements.

Impact of Inflation/Deflation and Pricing

All of our transactions are denominated in U.S. dollars. Typically, as prices for oil and natural gas increase, associated costs rise. Conversely, as prices for oil and natural gas decrease, costs decline. Cost declines tend to lag and may not adjust downward in proportion to declining commodity prices. Historically, field-level prices received for our oil and natural gas production have been volatile. During the year ended December 31, 2019, commodity prices increased during the first, second and third quarter, and subsequently decreased in the fourth quarter. During the three months ended March 31, 2020, commodity prices decreased compared to the same period in 2019. Changes in commodity prices impact our revenues, estimates of reserves, assessments of any impairment of oil and natural gas properties, as well as values of properties being acquired or sold. Price changes have the potential to affect our ability to raise capital, borrow money, and retain personnel.

Off-Balance Sheet Arrangements

As of March 31, 2020, we did not have material off-balance sheet arrangements.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK

We are exposed to market risk, including the effects of adverse changes in commodity prices and interest rates as described below. The primary objective of the following information is to provide quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil, natural gas and NGL prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. All of our market risk sensitive instruments were entered into for purposes other than speculative trading. LIBOR is used as a reference rate for certain of our financial instruments, such as our revolving credit facility. LIBOR is set to be phased out at the end of 2021. We are currently reviewing how the LIBOR phase-out will affect the Company, but we do not expect the impact to be material.

Commodity Price Risk

Our major market risk exposure is in the pricing that we receive for our oil, natural gas and NGL production. Pricing for oil, natural gas and NGL has been volatile and unpredictable for several years and this volatility is expected to continue in the future. The prices we receive for our oil, natural gas and NGL production depend on many factors outside of our control, such as the strength of the global economy and global supply and demand for the commodities we produce.

To reduce the impact of fluctuations in oil and natural gas prices on our revenues, we have periodically entered into commodity derivative contracts with respect to certain of our oil and natural gas production through various transactions that limit the downside of future prices received. We plan to continue our practice of entering into such transactions to reduce the impact of commodity price volatility on our cash flow from operations. Future transactions may include price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty. Additionally, we may enter into collars, whereby we receive the excess, if any, of the fixed floor over the floating rate or pay the excess, if any, of the floating rate over the fixed ceiling price. These hedging activities are intended to support oil prices at targeted levels and to manage our exposure to oil price fluctuations.

For a summary of the Company's commodity derivative contracts as of March 31, 2020, please see *Note 6—Commodity Derivative Instruments* in Part 1, Item 1 of this Quarterly Report.

As of March 31, 2020, the fair market value of our oil derivative contracts was a net asset of $236.4 million. Based on our open oil derivative positions at March 31, 2020, a 10% increase in the NYMEX WTI price would decrease our net oil derivative asset by approximately $34.2 million, while a 10% decrease in the NYMEX WTI price would increase our net oil derivative asset by approximately $30.6 million. As of March 31, 2020, the fair market value of our natural gas derivative contracts was a net asset of $16.0 million. Based upon our open commodity derivative positions at March 31, 2020, a 10% increase in the NYMEX Henry Hub price would decrease our net natural gas derivative asset by approximately $3.8 million, while a 10% decrease in the NYMEX Henry Hub price would increase our net natural gas derivative asset by approximately $3.9 million. Please see "—How We Evaluate Our Operations—Derivative Arrangements."

Counterparty and Customer Credit Risk

Our cash and cash equivalents are exposed to concentrations of credit risk. We manage and control this risk by investing these funds with major financial institutions. We often have balances in excess of the federally insured limits.

We sell oil, natural gas and NGL to various types of customers, including pipelines and refineries. Credit is extended based on an evaluation of the customer's financial conditions and historical payment record. The future availability of a ready market for oil, natural gas and NGL depends on numerous factors outside of our control, none of

which can be predicted with certainty. For the three months ended March 31, 2020, we had certain major customers that exceeded 10% of total oil, natural gas and NGL revenues. We do not believe the loss of any single purchaser would materially impact our operating results because oil, natural gas and NGL are fungible products with well-established markets and numerous purchasers.

At March 31, 2020, we had commodity derivative contracts with nine counterparties. We do not require collateral or other security from counterparties to support derivative instruments; however, to minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. Additionally, we use master netting agreements to minimize credit risk exposure. The creditworthiness of our counterparties is subject to periodic review. For the three months ended March 31, 2020 and 2019, we did not incur any losses with respect to counterparty contracts. None of our existing derivative instrument contracts contain credit risk related contingent features.

Interest Rate Risk

At March 31, 2020, we had $470.0 million variable-rate debt outstanding. The impact on interest expense of a 1% increase or decrease in the average interest rate would be approximately $4.7 million per year. We may begin entering into interest rate swap arrangements on a portion of our outstanding debt to mitigate the risk of fluctuations in LIBOR if we have variable-rate debt outstanding in the future. Please see "—Liquidity and Capital Resources—Debt Arrangements."

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of our disclosure controls and procedures to ensure that the information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms and to ensure that such information is accumulated and communicated to management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure. Based upon that evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were not effective as of March 31, 2020, due to the material weakness in internal control over financial reporting as described below.

Management's Material Weakness Remediation Plan

A material weakness is a deficiency, or combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis. Management determined that the Company did not design and maintain effective controls to determine the appropriate contract termination date and evaluate the potential accounting implications of changes in termination dates of contracts with customers. This material weakness resulted in a restatement of the Company's condensed consolidated financial statements as of and for the three and nine month periods ended September 30, 2019 and immaterial errors to the consolidated financial statements for the periods ended December 31, 2018, March 31, 2019 and June 30, 2019. The line items affected were oil sales, accounts payable and accrued liabilities, other non-current liabilities, inventory, prepaid expenses and other, and other non-current assets. Additionally, this material weakness could result in a misstatement of the aforementioned financial statement line items or disclosures that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected.

The Company and its Board of Directors are committed to maintaining a strong internal control environment. Management has evaluated the material weakness described above and developed a remediation plan to address the material weakness. The remediation plan includes additional procedures around determining the contract termination date pursuant to the accounting treatment under ASC 606 - Revenue from Contracts with Customers. Management is committed to successfully implementing the remediation plan and plans to commence the evaluation of its updated design of internal controls for implementation expeditiously.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the three months ended March 31, 2020 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Information regarding our legal proceedings can found in *Note 13—Commitments and Contingencies — Litigation and Legal Items* in Part I, Item 1. Financial Information in this Quarterly Report.

ITEM 1A. RISK FACTORS

Factors that could materially adversely affect our business, financial condition, operating results or liquidity and the trading price of our common stock are described below and under Item 1A "Risk Factors", included in our Annual Report on Form 10-K filed with the SEC on March 12, 2020. The risks described below and in our annual report are not the only risks facing us. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition or future results. This information should be considered carefully, together with other information in this report and other reports and materials we file with the SEC.

We have no additional borrowing capacity under our revolving credit facility. Unless we are able to successfully restructure our existing indebtedness, obtain further waivers or forbearance from our existing lenders or otherwise raise significant capital, it is unlikely that we will be able to meet our obligations as they become due, and we may not be able to continue as a going concern.

Our working capital deficit was $144.6 million and $240.8 million at March 31, 2020 and December 31, 2019, respectively, and our cash balances totaled $32.0 million and $32.4 million at March 31, 2020 and December 31, 2019, respectively. For the year ended December 31, 2019, the Company incurred net losses of approximately $1.4 billion. Our continuation as a going concern is dependent upon attaining and maintaining profitable operations and, until that time, raising additional capital as needed, but there can be no assurance that we will be able to obtain sufficient financing. Our ability to generate positive cash flow from operations is dependent upon generating sufficient revenues. To date, our operations have been funded by the sale of oil, gas and NGL production based on prevailing market prices, which decreased significantly in March and April 2020. Our operations have also been funded through availability on our credit facility. As discussed in *Note 4—Going Concern* in Part I, Item I, Financial Information of this Quarterly Report, on April 27, 2020 the lenders under the revolving credit facility elected to reduce the borrowing base and elected commitments to $650.0 million from $950.0 million, and we borrowed all of the remaining available capacity under the revolving credit facility. As a result of the reduction of the borrowing base and elected commitments, it is probable that the Company will not meet the financial covenants under the revolving credit facility for the three months ended June 30, 2020 when assuming the Company’s current financial forecast.

If the Company does not obtain a waiver of its financial covenants for the three months ended June 30, 2020, the lenders under the revolving credit facility will be able to accelerate maturity of the debt. Any acceleration of the obligations under the revolving credit facility would result in a cross-default and potential acceleration of the maturity of the Company’s other outstanding long-term debt. These defaults create uncertainty associated with the Company’s ability to repay its outstanding long-term debt obligations as they become due and creates a substantial doubt over the Company’s ability to continue as a going concern.

The accompanying Consolidated Financial Statements have been prepared on a going concern basis which contemplates continuity of operations, realization of assets and liquidation of liabilities in the ordinary course of business. The accompanying condensed consolidated financial statements do not reflect any adjustments that might result if we are unable to continue as a going concern. Our substantial indebtedness, liquidity issues and efforts to negotiate restructuring transactions may result in uncertainty about our business and cause, among other things:

- third parties to lose confidence in our ability to explore and produce oil and natural gas, resulting in a significant decline in our revenues, profitability and cash flow;
- difficulty retaining, attracting or replacing key employees;

- employees to be distracted from performance of their duties or more easily attracted to other career opportunities; and
- our suppliers, vendors, hedge counterparties and service providers to renegotiate the terms of our agreements, terminate their relationship with us or require financial assurances from us.

These events may have a material adverse effect on our business and operations.

The excess supply of oil and natural gas resulting from the reduced demand caused by the COVID-19 pandemic and the effects of actions by, or disputes among or between, oil and natural gas producing countries may result in transportation and storage constraints, reduced production and shut-in of our wells, any of which would adversely affect our business, financial condition and results of operations.

The recent worldwide outbreak of COVID-19, the uncertainty regarding the impact of COVID-19 and various governmental actions taken to mitigate the impact of COVID-19, have resulted in an unprecedented decline in demand for oil and natural gas. At the same time, the decision by Saudi Arabia in March 2020 to drastically reduce export prices and increase oil production followed by curtailment agreements among OPEC and other countries such as Russia further increased uncertainty and volatility around global oil supply-demand dynamics. To the extent that the outbreak of COVID-19 continues to negatively impact demand and OPEC members and other oil exporting nations fail to implement production cuts or other actions that are sufficient to support and stabilize commodity prices, we expect there to be excess supply of oil and natural gas for a sustained period. This excess supply could, in turn, result in transportation and storage capacity constraints in the United States, including in the DJ Basin. If, in the future, our transportation or storage arrangements become constrained, we may incur significant operational costs if there is an increase in price for services or we may be required to shut-in or curtail production or flare our natural gas. If we were required to shut-in wells, we might also be obligated to pay certain demand charges for gathering and processing services and firm transportation charges for pipeline capacity we have reserved. Further, any prolonged shut-in of our wells may result in decreased well productivity once we are able to resume operations, and any cessation of drilling and development of our acreage could result in the expiration, in whole or in part, of our leases. All of these impacts resulting from the confluence of the COVID-19 pandemic and the price war between Saudi Arabia and Russia may adversely affect our business, financial condition and results of operations.

Due to the commodity price environment, we have postponed or eliminated a portion of our developmental drilling. A sustained period of weakness in oil, natural gas and NGLs prices, and the resultant effects of such prices on our drilling economics and ability to raise capital, will require us to reevaluate and further postpone or eliminate additional drilling. Such actions would likely result in the reduction of our PUDs and related PV-10 and a reduction in our ability to service our debt obligations. If we are required to further curtail our drilling program, we may be unable to continue to hold leases that are scheduled to expire, which may further reduce our reserves. As a result, if oil, natural gas and/or NGLs prices experience a sustained period of weakness, our future business, financial condition, results of operations, liquidity, and ability to finance planned capital expenditures may be materially and adversely affected.

The inability to renegotiate our transportation and marketing contracts may adversely affect our business and financial condition.

We enter into firm transportation, gas processing, gathering and compression service, water handling and treatment, or other agreements that require minimum volume delivery commitments in the normal course of our business. During the spring of 2020, in light of market conditions, we began renegotiating our transportation, gathering and marketing contracts to reduce, restructure or eliminate our minimum volume commitments to our transportation, gas processing and gathering and compression service providers. Any inability to renegotiate transportation and marketing contracts to reflect current market conditions increases our marketing and transportation costs, inclusive of costs related to unutilized transportation and/or processing capacity for previously planned volumes. Such increased costs decrease realized revenue at any notional commodity value, negatively impacting financial results, competitiveness, and our overall financial condition. If we are unable to modify our minimum volume commitments, we may not have sufficient production to fulfill them which would have an adverse effect on our business and financial condition.

Failure to maintain the continued listing standards of NASDAQ could result in delisting of our common stock, which could negatively impact the market price and liquidity of our common stock and our ability to access the capital markets.

Our shares are listed on the NASDAQ Global Market ("NASDAQ") and the continued listing of our shares on NASDAQ is subject to our ability to comply with NASDAQ's continued listing requirements, including, among other things, a minimum closing bid price requirement of $1.00 per shares. On March 30, 2020, we received a letter from the Listing Qualifications Department of NASDAQ notifying us that our shares closed below the $1.00 per unit minimum bid price required by NASDAQ Listing Rule 5450(a)(1) for 30 consecutive business days and that we have a period of 180 calendar days in which to regain compliance.

We are considering options to regain compliance. If we are unable to regain compliance, however, any delisting from NASDAQ could result in even further reductions in our price per share, substantially limit the liquidity of our common stock, and materially adversely affect our ability to raise capital or pursue strategic restructuring, refinancing or other transactions on acceptable terms, or at all. Delisting from the NASDAQ could also have other negative results, including the potential loss of institutional investor interest and fewer business development opportunities.

There is no assurance that we will continue to maintain compliance with NASDAQ continued listing standards. Our business has been and may continue to be affected by worldwide macroeconomic factors, which include uncertainties in the credit and capital markets as well as with respect to commodity prices. External factors that affect our share price, such as liquidity requirements of our investors, as well as our performance, could impact our market capitalization, revenue and operating results, which, in turn, affect our ability to comply with the NASDAQ's listing standards. The NASDAQ has the ability to suspend trading in our shares or remove our shares from listing on the NASDAQ if in the opinion of the exchange: (a) the financial condition and/or operating results of the Company appear to be unsatisfactory; (b) it appears that the extent of public distribution or the aggregate market value of our units has become so reduced as to make further dealings on the exchange inadvisable; (c) we have sold or otherwise disposed of our principal operating assets, or have ceased to be an operating company; (d) we have failed to comply with our listing agreements with the exchange; or (e) any other event shall occur or any condition shall exist which makes further dealings on the exchange unwarranted.

There is substantial risk that it may be necessary for us to seek protection under Chapter 11 of the United States Bankruptcy Code, which may have a material adverse impact on our business, financial condition, results of operations, and cash flows, would have a material adverse impact on the trading price of our securities, and could place our shareholders at significant risk of losing all of their investment in our shares.

We have engaged financial and legal advisors to assist us in, among other things, analyzing various strategic alternatives to address our liquidity and capital structure, including strategic and refinancing alternatives to restructure our indebtedness in private transactions. Due to our current financial constraints, there is a substantial risk that it may be necessary for us to seek protection under Chapter 11.

Seeking bankruptcy court protection could have a material adverse effect on our business, financial condition, results of operations and liquidity. As long as a Chapter 11 proceeding continues, our senior management would be required to spend a significant amount of time and effort dealing with the reorganization instead of focusing on our business operations. Bankruptcy court protection also may make it more difficult to retain management and other key personnel necessary to the success and growth of our business. In addition, during the period of time we are involved in a bankruptcy proceeding, our customers and suppliers might lose confidence in our ability to reorganize our business successfully and may seek to establish alternative commercial relationships.

Additionally, all of our indebtedness is senior to the existing common stock and preferred stock in our capital structure. As a result, we believe that seeking bankruptcy court protection under a Chapter 11 proceeding could cause the shares of our existing common stock to be canceled, result in a limited recovery, if any, for shareholders of our common stock, and would place shareholders of our common stock at significant risk of losing all of their investment in our shares.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5. OTHER INFORMATION

We are providing the following disclosure in lieu of filing a Current Report on Form 8-K relating to "Item 5.02 Departure of Directors or Certain Officers; Election of Directors; Appointment of Certain Officers; Compensatory Arrangements" of Form 8-K.

On May 8, 2020, the Company entered into an Indemnification Agreement (the "Indemnification Agreement") with Marianella Foschi. The Indemnification Agreement requires the Company to indemnify Ms. Foschi to the fullest extent permitted under Delaware law against liability that may arise by reason of her service to the Company, and to advance certain expenses incurred as a result of any proceeding against her as to which she could be indemnified.

The foregoing description of the Indemnification Agreement is not complete and is qualified in its entirety by reference to the full text of the Indemnification Agreement, which is attached as Exhibit 10.10 to this Current Report on Form 10-Q and incorporated into this Item 5 by reference.

ITEM 6. EXHIBITS

(a) Exhibits:

The exhibits listed on the accompanying Exhibit Index are filed, furnished or incorporated by reference as part of this report, and such Exhibit Index is incorporated herein by reference.

INDEX TO EXHIBITS

Exhibit Number	Description
3.1	Certificate of Incorporation of Extraction Oil & Gas, Inc., dated October 11, 2016 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 14, 2016).
3.2	Certificate of Designations of Series A Preferred Stock of Extraction Oil & Gas, Inc., filed with the Secretary of State of the State of Delaware on October 17, 2016 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
3.3	Bylaws of Extraction Oil & Gas, Inc., dated October 11, 2016 (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 14, 2016).
†10.1	Restricted Stock Unit Award Agreement (Thomas B. Tyree) (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on March 5, 2020).
†10.2	Employment Agreement dated as of March 4, 2020, between the Company and Thomas B. Tyree (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on March 5, 2020).
†10.3	Indemnification Agreement (Thomas B. Tyree) (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on March 5, 2020).
†10.4	Amended and Restated Employment Agreement effective as of March 4, 2020, between the Company and Matt Owens (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on March 5, 2020).
†10.5	Extraction Oil & Gas, Inc. Executive Severance Plan (incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on March 5, 2020).
†10.6	Form of Participation Agreement (Executive Severance Plan) (incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on March 5, 2020).
†10.7	Employment Transition Agreement, dated March 18, 2020, between Extraction Oil & Gas, Inc., XOG Services, LLC. and Mark A. Erickson (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on March 20, 2020).
†10.8	Form of Restricted Stock Unit Award Agreement (Performance-Vesting, Share-Settled) (for Officers) (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on March 20, 2020).
†10.9	Form of Restricted Cash Award Agreement (Employees) (incorporated by reference to Exhibit 10.3 to the Company's 8-K (File No. 001-37907) filed with the Commission on March 20, 2020).
*†10.10	Indemnification Agreement (Marianella Foschi)
*31.1	Certification of Chief Executive Officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934.
*31.2	Certification of Chief Financial Officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934.
**32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
**32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*101	Interactive Data Files

† Management contract or compensatory plan or agreement.

* Filed herewith.

** Furnished herewith.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: May 11, 2020.

Extraction Oil & Gas, Inc.

By: /S/ MATTHEW R. OWENS
Matthew R. Owens
President and Chief Executive Officer
(principal executive officer)

By: /S/ TOM L. BROCK
Tom L. Brock
Vice President and Chief Accounting Officer
(principal financial officer)

EXHIBIT BB

FULLY REDACTED

CERTIFICATE OF SERVICE

I, Brett S. Turlington, certify that I am not less than 18 years of age, and that service of the foregoing *Notice of Filing of Proposed Redacted Version of Platte River Midstream, LLC and DJ South Gathering, LLC's Response in Opposition to Extraction Oil & Gas, Inc.'s Motion for Summary Judgment* was caused to be made on September 24, 2020, in the manner indicated upon the entities identified below.

HAND DELIVERY AND ELECTRONIC MAIL

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FIRST-CLASS MAIL AND ELECTRONIC MAIL

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Anna Rotman, P.C.
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kenneth.young@kirkland.com

Date: September 24, 2020

/s/ Brett S. Turlington
Brett S. Turlington (No. 6705)