The Board of Trustees

of the

School and Institutional Trust Lands Administration

Subject: Written determinations concerning June 17, 2021 Board Meeting

Roger Barrus, as Chairman of the Board of Trustees (the "Board") of the School and Institutional Trust Lands Administration, pursuant to Utah Code Section 52-4-207(4), hereby makes the following determinations concerning the need to hold an electronic meeting of the Board, without an anchor location, on June 17, 2021.

Facts upon which determination is based:

- Federal, State and local authorities have recommended that individuals limit public gatherings and that individuals experiencing symptoms of COVID-19 self-isolate to prevent and control the continuing spread of COVID-19.
- The public monitoring and participation requirements, and the anchor location requirement, in the Open and Public Meetings Act, Utah Code Section 52-4-101 et seq. will gather interested persons, members of the public, and members of a public body in a single, confined location where the risks of further spreading COVID-19 are far greater.

Determination concerning conduct of June 17, 2021 Board meeting:

- In light of the facts referenced above, conducting the June 17, 2021 meeting with an anchor location at which the public and other interested parties are permitted to attend presents a substantial risk to the health and safety of those who may be present at the anchor location;
- The Board will therefore hold an electronic meeting without an anchor location, and will provide an electronic means by which the public may hear the open portions of the meeting, as well as an electronic means by which members of the public may provide comment to the Board;
- The above findings will be included within the public notice of the June 17, 2021 meeting, and will be read into the record at the beginning of that meeting.

Entered this 7th day of June, 2021.

BOARD OF TRUSTEES, FOR THE UTAH SCHOOL AND INSTITUTIONAL TRUST LANDS ADMINISTRATION

Roger Barrus

Roger Barrus, Chairman

Agenda

Board of Trustees Meeting Agenda

Thursday, June 17, 2021

9:00 a.m.

VIRTUAL ELECTRONIC MEETING

Notice regarding special restrictions for this electronic meeting.

In light of federal, state and local COVID-19 guidelines, and consistent with the Board chairperson's written determination dated June 7, 2021, this Board of Trustees meeting will be held via electronic means only. No anchor location will be used, and members of the public will not be allowed to attend this meeting in person. The Board chairperson's June 7, 2021 determination concerning the conduct of the June 17, 2021 meeting included the following:

<u>Facts upon which determination of need to hold an electronic meeting of the Board, without an anchor location, on June 7, 2021, is based:</u>

Federal, State, and local authorities have recommended that individuals limit public gatherings and that individuals experiencing symptoms of COVID-19 self-isolate to prevent and control the continuing spread of COVID-19.

The public monitoring and participation requirements in the Open and Public Meetings Act, Utah Code Section 52-4-101 et seq. will gather interested persons, members of the public, and members of a public body in a single, confined location where the risks of further spreading COVID-19 are far greater.

<u>Determination concerning conduct of June Board meeting:</u>

In light of the facts referenced above, conducting the June 17, 2021 meeting with an anchor location presents a substantial risk to the health and safety of those who may be present at the anchor location;

The Board, consistent with its recent practice under Utah Executive Order 2020-5, will therefore hold an electronic meeting without an anchor location, and will provide an electronic means by which the public may hear the open portions of the meeting, as well as an electronic means by which members of the public may provide comment to the Board;

The above findings will be included within the public notice of the June 17, 2021 meeting, and will be read into the record at the beginning of that meeting.

This meeting will be conducted via Zoom. Interested parties, including members of the public or representatives of county governments or Utah Tribes, may attend the meeting through the following registration link: https://zoom.us/webinar/register/WN_TFtV_zPXTXaTuAEDsSfBeg.

We recommend registering by 8:50 a.m. to avoid missing the beginning of the meeting. Those wishing to provide public comment will be asked at the beginning of the period designated for such comment to use the "raise hand" feature at the bottom of the screen within the Zoom meeting so they may be called upon to provide comment. Please call Lisa Jones at 801-538-5110 or email lsjones@utah.gov any time before 8:00 a.m. on June 17, 2021 with questions.

1. Welcome

2. Approval of Minutes

May 13, 2021

May 20, 2021

3. Confirmation of Upcoming Meeting Dates

July 15, 2021 NO Scheduled Meeting

August 19, 2021

September 16, 2021

4. SITLA Funds in the Schools by Deena Loyola, Public Information Officer

5. Public Comments

SITLA welcomes comments *from the public. The Board sets aside 15 minutes at each Board meeting to hear from anyone wishing to speak. Each presenter is allowed one opportunity and has up to three (3) minutes for remarks. Any member of the public who desires to make a comment shall use the "raise hand" feature during the Zoom meeting. The public comment segment of the Board meeting is not the time for a question-and-answer discussion. SITLA staff are available for dialogue outside of Board meetings.*

6. Chair's Report by Roger Barrus

7. Advocate Report by Tim Donaldson, Director, Land Trusts Protection & Advocacy Office

8. Director's Report by Dave Ure

9. Notification & Discussion Items

Notification items do not require Board action and are only informational. Staff is prepared to discuss any of the items if a member of the Board requests it -- NONE

10. Board Action Items

a. Initiation of process to adopt proposed new rule (R850-13) concerning confidential treatment of proprietary information and to amend exiting rule (R850-6) concerning the Government Records Access and Management Act by Mike Johnson, Chief Legal Counsel

b. Request for Approval, Addition to a Major Development Transaction – Kayenta Development Lease and Option by Aaron Langston, Deputy Assistant Director, Planning & Development – St. George

c. Other Business Arrangement – Non-Competitive Lease of Metalliferous Minerals OBA with Kennecott Utah Copper, LLC. by Jerry Mansfield, Resource Specialist, Mining

d. SITLA's Proposed Edits to Interim Order in EOG v SITLA by Mike Johnson, Chief Legal Counsel & Mark Burns, SITLA Board Attorney

e. Seep Ridge & Holliday Block OBA (Oil & Gas) – Amend & Replace by Wes Adams, Assistant Director, Oil & Gas

f. Montezuma Creek OBA (Helium) by Wes Adams, Assistant Director, Oil & Gas

g. Book Cliffs OBA (Helium) by Wes Adams, Assistant Director, Oil & Gas

11. Closed Session

a. Pursuant to Utah Code Section 52-4-205(1)(e), the Board will conduct a strategy session to discuss the sale of real property where public discussion of the proposed transaction would disclose the appraisal or estimated value of the property or prevent the Board from completing the transaction on the best possible terms. Specifically, the Board will hold a strategy session to discuss the proposed sale of approximately 480 acres of land in Weber County, Utah.

b. Pursuant to Utah Code §53C-1-201(8)(a)(i), the Board will conduct a strategy session to discuss market conditions relevant to the sale of particular trust assets where public discussion would disclose the estimated value of the trust asset or prevent the Board from completing the contemplated transaction on the best possible terms. Specifically, the Board will discuss market conditions relevant to the potential sale of trust lands in Cache County, Utah. The terms of any eventual sale will be publicly disclosed before the board approves such a sale.

c. Pursuant to Utah Code §53C-1-201(8)(a)(ii), the Board will conduct a strategy session to evaluate the terms of a joint venture or other business arrangement (OBA) authorized under Subsection 53C-1-303(3)(e) where public discussion of the transaction would disclose the estimated value of the trust asset under consideration or prevent the Board from completing the transaction on the best possible terms. Specifically, the Board will discuss potential joint venture or OBA terms concerning trust lands within the Northwest Quadrant of Salt Lake City. In this closed session concerning trust land within the Northwest Quadrant, the Board will also, pursuant to Utah Code §53C-1-201(8)(i), conduct a strategy session to discuss market conditions relevant to the Northwest Quadrant trust assets.

12. Board Action

Following the closed session, if the Board deems the matter ready for action, the Board will act on the proposed sale of approximately 480 acres of land in Weber County, Utah. The Administration and Board will publicly disclose the terms of the sale prior to the Board taking action.

13. Adjourn

10a

Rules Changes R850-13 & R850-6

BOARD MEMORANDUM

TO: Board of Trustees, School and Institutional Trust Lands Administration

FROM: Mike Johnson, Chief Legal Counsel

DATE: June 2, 2021

SUBJECT: Initiation of process to adopt proposed new rule (R850-13) concerning confidential treatment of proprietary information and to amend existing rule (R850-6) concerning the Government Records Access and Management Act.

BACKGROUND INFORMATION

The School and Institutional Trust Lands Administration (SITLA) frequently requests and receives confidential business information from applicants, lessees, partners, permittees, and other third parties desiring to do business with the agency. SITLA's receipt of such proprietary information is necessary to allow the agency to fully evaluate a project or other proposal. The providers of such information are understandably concerned that any proprietary information submitted remain protected. The Government Records Access and Management Act (GRAMA) provides a measure of protection by permitting State agencies to keep certain types of third-party commercial information confidential where (i) disclosure could cause competitive injury to the provider; (ii) the provider has a greater interest in confidentiality than the public does in disclosure; and (iii) the provider provides a claim of confidentiality with an explanation of the reasons at the same time the information is submitted. *See* Utah Code § 63G-2-305.

SITLA's enabling statute provides independent and slightly broader authority to keep proprietary information confidential. *See* Utah Code § 53C-2-102[1]. The statute instructs the Director to adopt rules implementing its provisions. The agency's current rules contain a section regarding GRAMA, R850-6, which cites § 53C-2-102 as one of the authorities supporting the rule; however, that rule extends the protection authorized under Section 102 only to mineral-related information. In light of this limitation, SITLA proposes a new rule specifically addressing confidential treatment of third-party proprietary information and to amend the current GRAMA rule as necessary to fully implement § 53C-2-102. SITLA asks the Board to authorize SITLA to take the steps necessary to adopt the new rule and amendments, which begins with publication of the proposed changes in the Utah State Bulletin for public comment. If

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[1] The statute provides in full:

(1) As used in this section, "provider" means a prospective applicant, applicant, partner, or lessee.

(2) (a) The administration may require a provider to furnish any information necessary to carry out the duties of this title, including financial information, geological and mine maps, well logs, and assays.

(b) Any information submitted to the administration which the provider and the director agree in writing is of a proprietary nature shall be kept confidential and may not be released without written permission from the provider.

(3) The director shall adopt rules under which the administration may retain, without disclosure to third parties, information including that received under Subsection (2) which the provider and the director agree is of a protected or proprietary nature, unless the information is required by federal or state law to be of a nonproprietary nature.

public comment results in substantive edits to the proposed rule, SITLA will bring the rule back to the Board for further review. Otherwise, the rule will become final following the public comment period.

PROPOSED NEW RULE R850-13—CONFIDENTIAL TREATMENT OF PROPRIETARY INFORMATION

The proposed rule R850-13 defines "proprietary information" as information owned or controlled by the provider, that provides a competitive business advantage to the provider, and that SITLA could not otherwise obtain through public sources. This definition encompasses information that would otherwise be non-public which SITLA desires to review to evaluate a project or proposal. The proposed rule creates a process for a provider to submit proprietary information and make a request for confidential treatment, and includes a requirement that SITLA hold as confidential any such information the agency agrees is proprietary. Such an agreement can be made before or after the information is submitted to the agency, and SITLA is not required to weigh the public's interest against the provider's interest in keeping the information confidential. The rule is designed, in light of SITLA's unique mandate and frequent execution of contracts and other business arrangements with third parties, to permit the agency to treat proprietary information as confidential and to more effectively transact trust lands business.

PROPOSED AMENDMENTS TO RULE R850-6—GOVERNMENT RECORDS ACCESS AND MANAGEMENT ACT

SITLA also proposes amending the GRAMA rule, R850-6. Much of the current rule mirrors provisions of GRAMA itself, and SITLA proposes to remove duplicative provisions to comply with the rulewriting manual published by the Utah Office of Administrative Rules. SITLA also proposes including a provision prohibiting disclosure of proprietary information protected under § 53C-2-102 and R850-13.

The Legal Committee reviewed the proposed rule changes discussed above, which are set forth below as a part of this memo, and recommended that they be presented to the full Board for consideration.

RECOMMENDATION

Staff recommends the Board of Trustees approve transmitting to the Office of Administrative Rules the proposed new rule concerning confidential treatment of proprietary information (R850-13), as well as the proposed amendments to the rule governing GRAMA (R850-6). The Office of Administrative Rules will publish the proposed changes in the Utah State Bulletin and there will be a minimum 30-day public comment period. No final action will be taken on the proposed rule changes until after any public comments are considered.

R850. School and Institutional Trust Lands, Administration.
R850-13. Confidential Treatment of Proprietary Information.
R850-13-100. Authorities.

1. This rule implements Section 53C-2-102(3), which gives the agency independent authority to keep information owned by third parties confidential.

2. This rule is authorized by Sections 6, 8, 10, and 12 of the Utah Enabling Act, Articles X and XX of the Utah Constitution, and Sections 53C-1-302(1)(a)(ii) and 53C-2-102(3) of the Utah Code.

R850-13-200. Definitions.

In addition to the terms defined in R850-1 and Section 53C-2-102, the terms below, when used in R850-13 are defined as follows:

1. “Propriety information” means information in any form that is owned or controlled by the provider, which the agency could not reasonably obtain through public sources, and which provides a competitive business advantage to the provider, including financial, business, engineering, and geologic information and analysis.

2. “Provider” means a prospective applicant, applicant, partner, permittee, lessee, or any other third party that provides the agency with proprietary information for the purpose of entering into a potential transaction or as required by the agency under the terms of any permit, lease, or other business arrangement.

R850-13-300. Request for Proprietary Information.

1. The agency may require that a provider submit proprietary information:

(a) to evaluate a potential or submitted application, bid, proposal, or agreement;

(b) as part of negotiating a potential agreement with a third party; or

(c) to assess the value and uses of trust lands for potential sale, lease, permit, exchange, or other business arrangement.

2. The agency may reject an application, request for proposal, or other transaction if the provider fails to submit the required proprietary information.

3. The agency may require that a lessee, permittee, or any other party in a contractual relationship with the agency submit proprietary information to the agency as the agency deems reasonable and necessary to determine the provider’s compliance with the terms of the contract.

R850-13-400. Submitting Proprietary Information under Confidentiality.

1. If the agency requires and/or a provider desires to submit proprietary information to the agency under confidentiality, the provider shall make a written request for confidentiality to the director. The request for confidentiality must contain:

(a) a claim that the information is of a proprietary nature and a concise statement of reasons supporting the claim;

(b) a claim that the information has not been publicly disclosed; and

(c) a request for confidential treatment of any or all of the proprietary information.

2. The director shall notify the provider in writing of whether the director agrees that any or all of the information is of a proprietary nature. To the extent possible, the agency shall not review the substantive details of the information submitted under a confidentiality request until after the director has agreed that the information is proprietary in nature. If the director does not agree that the information is proprietary, the director shall notify the provider and upon the provider’s request, return the information to the provider.

3. A provider may make a confidentiality request prior to or after submitting the proprietary information to the agency. Failure to request confidential treatment of proprietary information before the agency discloses the information to a third party constitutes waiver of a claim of confidentiality with respect to the proprietary information so disclosed.

4. The director and provider may agree in writing that certain categories of information are proprietary and such agreement means that all information previously submitted, or thereafter submitted, within the agreed-upon category will be treated as confidential pursuant to R850-13-500.1.

5. The agency may execute a confidentiality agreement with a provider consistent with these rules.

R850-13-500. Confidentiality Obligations of the Agency.

1. The agency shall keep confidential all information:

(a) submitted under a request for confidentiality pursuant to R850-13-400.1 that the director agrees is of a proprietary nature; or

(b) that is proprietary information and submitted pursuant to R850-13-400.4 or R850-13-400.5.

2. The agency may not disclose proprietary information subject to confidentiality under R850-13-500.1 to third parties unless:

(a) the provider agrees to the disclosure in writing;

(b) the information becomes publicly available other than through disclosure by the agency;

(c) the information is provided to the agency by a third party that has no confidentiality obligation to the provider with respect to the disclosed information;

(d) the information is independently developed by the agency without use of the proprietary information;

(e) the information is required to be disclosed by an administrative or judicial order; or

(f) federal or state law requires the information to be of a non-proprietary nature.

R850-13-600. Return or Destruction of Proprietary Information.

1. At the request of the provider, the agency shall return all proprietary information to the provider and destroy any proprietary information held in digital form, except that the agency may retain:

(a) proprietary information related to the characteristics of trust lands; and

(b) proprietary information required to be submitted under a lease or other contract through the term of the contract.

2. The agency is not required to destroy proprietary information held in digital back-up files or archives if retaining the information is consist with the State’s records retention policy so long as the agency uses reasonable efforts to ensure proprietary information remains confidential.

R850. School and Institutional Trust Lands, Administration.
R850-6. Government Records Access and Management.
R850-6-100. Purposes and Authority.

1. This rule provides procedures for appropriate access to agency records under the Government Records Access and Management Act.

2. This rule is authorized by Sections 6, 8, 10, and 12 of the Utah Enabling Act; Articles X and XX of the Utah Constitution; and Sections 63A-12-104, 63G-2-204, and 53C-1-201(3)(a)(i)(A~~), and 53C-2-102.~~).

R850-6-200. Definitions.

~~1. Terms used in this rule are~~In addition to the terms defined in ~~Section 63G-2-103.~~

~~2. In addition~~R850-1, the term~~s~~ "records specialist"~~ below~~, when used in R850-6, ~~mean the following:~~

~~(a) "Records coordinators: individuals~~ specialist" means the individual designated by the ~~agency~~ director to ~~coordinate records access requests and to~~ assist the public in gaining access to records maintained by the agency.~~ Records coordinators are located in the Salt Lake Office, 675 East 500 South, Suite 500, Salt Lake City, UT 84102.~~

R850-6-300. ~~Allocation of Responsibility Within the Agency~~Requests for Records.

~~The agency is considered a governmental entity and the director of the agency is considered the head of the government entity.~~

~~**R850-6-400. Requests for Access.**~~

~~1. Request for access to records shall be on a form provided by the agency or in another legible written document which contains the following information: the requester's name, mailing address, daytime telephone, a description of the records requested that identifies the record with reasonable specificity, and if the record is not public, information regarding requester's status.~~

~~2. The request shall be submitted to the records officer or coordinator. The response to the request may be delayed if not properly directed.~~

~~3.~~ 1. A person may request a record by submitting a request to the records specialist using the agency's form or as otherwise provided in Section 63G-2-204. Failure to submit the records request on the agency's form may delay the agency's response.

2. In addition to the reasons set forth in Title 63G, Chapter 2, Part 3 of the Utah Code, t~~T~~he agency shall deny a request for ~~private, controlled, protected or limited access records if the request is not made in writing and does not contain information required in this section.~~

~~4. Notwithstanding the provision of subsection 63G-2-204(1), the agency may, at its discretion, waive the requirement for a written request if the records requested are public, the records are readily accessible and the request is filled promptly by providing access or copying at the time the request is made.~~

~~**R850-6-500. Other Requests.**~~

~~1. For research purposes:~~

~~Access requests for private or controlled records for research purposes pursuant to Section 63G-2-202(8), shall be made in writing and directed only to the records officer.~~

~~2. To amend a record:~~

~~An individual may contest the accuracy or completeness of a document pertaining to him as maintained by the agency pursuant to Section 63G-2-603.~~

~~(a) The request to amend shall be made in writing to the records officer.~~

~~(b) Appeals of requests to amend a record shall be handled as informal hearings~~records that are confidential under ~~the Utah Administrative Procedures Act.~~

~~3. To claim business confidentiality:~~

~~A request for protected records status based on a claim of business confidentiality may be made pursuant to Section 63G-2-309. Such a request shall be submitted in writing to the director or his designee. The request shall contain the claim of business confidentiality and a concise statement of reasons supporting the claim of business confidentiality.~~

~~4. To claim limited records status:~~

~~A lessee may claim that mineral information provided to the agency should be protected under Section~~ 53C-2-102~~.~~

~~(a) Such a request shall be submitted in writing to the director or his designee. The request shall contain a claim that the information provided the agency is of a proprietary nature and a concise statement of reasons supporting the claim.~~

~~(b) If the agency agrees the information is of a proprietary nature, the request shall be granted and the information shall receive limited records status until:~~

~~i) the lease is terminated and the agency believes the release of the information is not detrimental to the trust; or~~

~~ii) the lessee or its successor in interest ceases to exist as an entity and the agency believes the release of the information is not detrimental to the trust.~~

~~(c) A record granted limited records status under this section shall not be released to another party without written permission from the lessee providing the information during the period the limited records status is in effect.~~

~~(d) The agency may make information provided limited records status under this section available for inspection, but not for copying, by the Utah Geological Survey or the Division of Oil, Gas and Mining if consultation is requested by the agency, provided further that the confidentiality of such information is safeguarded.~~

and R850-~~6-600. Denials~~13.

~~1. If any access or status request is denied in whole or in part, a notice of denial shall be given to the requester in person or sent to the requester's address.~~

~~2. The notice of denial shall contain the information required in subsection 63G-2-205(2).~~

~~**R850-6-700. Appeal of Determination.**~~

~~1. Any person aggrieved by an access or status request determination including a person not a party to the agency proceeding may, within 30 days after the determination, appeal the determination to the director by submitting a notice of appeal either on a form provided by the agency or another legible written document which contains the following information: the petitioner's name, mailing address and daytime telephone number (if available); and the relief sought.~~

~~2. Upon receiving the notice of appeal and review of relevant information including that submitted with the appeal and criteria prescribed in Sections 63G-2-204, 63G-2-603, and 53C-2-102, the director may:~~

~~(a) uphold the original classification or status request determination; or,~~

~~(b) reclassify the record if he believes the original classification was incorrect; or,~~

~~(c) release the record regardless of its classification if the director believes that the interest of the public in obtaining access to the record outweighs the interest of the agency in prohibiting access to the record.~~

~~**R850-6-800. Fees.**~~

~~1. A fee schedule for the direct and indirect costs of duplicating or compiling a record may be obtained from the records officer or any records coordinator located at the addresses provided in R850-6-200, Definitions.~~

KEY: GRAMA, government documents, public records
Date of Enactment or Last Substantive Amendment: August 7, 2018
Notice of Continuation: June 27, 2017
Authorizing, and Implemented or Interpreted Law: 53C-1-201(3)(a)(i)(A~~); 53C-2-102~~)

10b

Kayenta Development Lease & Option

Memorandum

TO: Board of Trustees, School and Institutional Trust Lands Administration

FROM: Aaron Langston, Deputy Assistant Director, P&DG Utah South

DATE: June 17, 2021

RE: ***Request for Approval, addition to a Major Development Transaction – Kayenta Development Lease and Option***

BENEFICIARY: Schools

History

Kayenta Homesites Inc ("Kayenta") allowed their development lease (DEVL 646) to expire in 2016 primarily because of a city-imposed requirement for sewer in a community that had up until that time been on a septic system. By 2018, Kayenta had resolved the former issues and was ready to reenter into a development agreement with the Trust. This new agreement (DEVL 1160) was executed in 2018.

Approximately 87.47 acres from DEVL 1160 had complex issues, including clay soils, rock, and jurisdictional washes, and as such they were valued separately from the other lands in the development lease. Those troubled lands, comprising eight different parcels (1A, 1B, 2, 3, 4A, 4B, 5, and 6), were appraised with an average per-acre valuation of $46,194.

By early 2020, most of the parcels within DEVL 1160 had been taken down and our development partner was ready to annex the surrounding SITLA lands that had the highest development potential into the development lease. These additional lands (parcels 7, 8, 11, and 12) totaled 23.28 acres, were made part of the Lease in 2020, and brought an additional $1.107 million to the Trust (approximately $50,037 per acre).

Our development partner now wishes to annex the remainder of our Kayenta lands into the development lease. We have identified approximately 69 acres of lands that could be developed (parcels 10a, 10b, 10c, 14, 15a, 15b, 15c, 15d, 16a, 16b, 17, and 18).

The Offers

Kayenta Development wishes to acquire all the remaining lands in our Kayenta portfolio, which would include approximately 69 acres of developable parcels and 223 acres of open space lands.

However, the Washington County Water Conservancy District (WCWCD) anticipates purchasing a significant portion of those lands for a proposed reservoir. Staff feels it is important to favor the WCWCD because of possible water shortage concerns. Kayenta Development would be able to acquire all Kayenta lands not needed for the proposed reservoir.

Recognizing the actual lands needed for the Reservoir may change slightly, Staff proposes allowing Kayenta Development to initially annex the lands to the west into the existing development lease, which is approximately 45.61 acres of development land (parcels 15a, 15b, 15c, 15d, 16a, and 16b) and 59.84 acres of open space lands. The remainder of the lands would be available to the WCWCD, but if the WCWCD chooses not to move forward with the proposed reservoir, or if they end up not needing all the remainder of the lands, Kayenta Development will simply annex those additional properties into its development lease.

These transactions will be based on appraised value. The April 2021 appraisal assigned values of the subject development lands ranging from $53,000 to $70,000 per acre, averaging $60,280.38 per acre, with the open space parcels coming in at $4,500 per acre. Not surprisingly, these per-acre valuations far exceeded those established in the 2020 appraisal for different parcels, even though the lands in this new appraisal are more challenging than the previous parcels.

<u>Deal Structures</u>

Upon Board approval, Staff will do a fee simple transaction with the WCWCD for the disposal of the lands needed for the proposed reservoir, and the remainder of the lands will be added to the existing development lease with Kayenta Development.

Kayenta Development will be taking down open space parcels in proportion to the development lands so that we are not left with any remaining property in Kayenta. A 3% per annum escalation will be effective at each anniversary of the signed date of the amendment. DEVL 1160 has a seven-year term with one three-year option at either party's discretion. It is not anticipated that additional time would be needed.

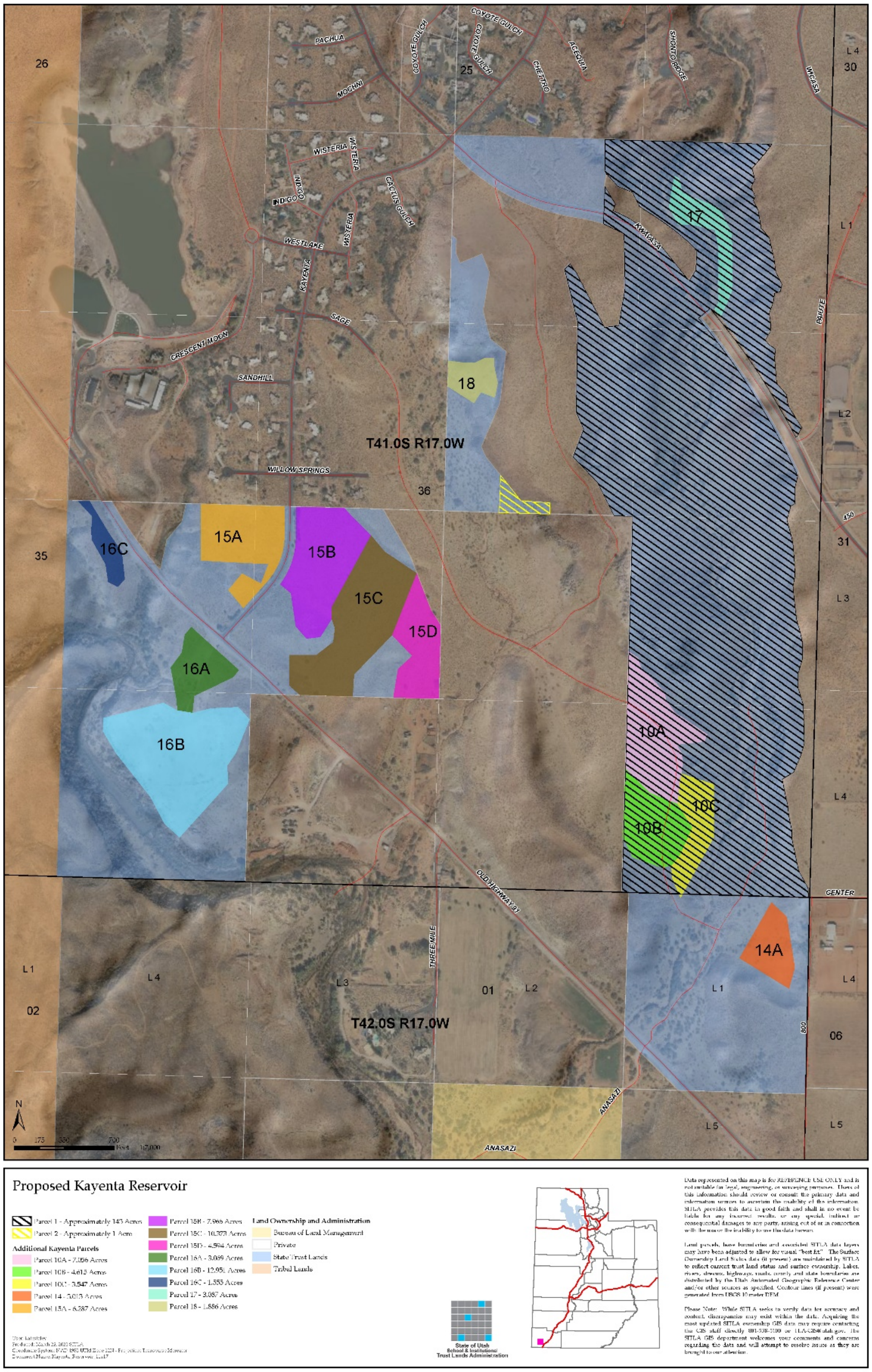
<u>Intended Action</u>

Staff thinks the proposed offer meets the intent of the general plan, meets its fiduciary responsibility to the Trust by disposing of the property at current market prices, and thereby supports this transaction. Upon Board approval, Staff will add a portion of the subject lands to the existing development lease and the remainder will be sold directly to the WCWCD as outlined above.

This proposal was vetted by the Real Estate Committee on March 22, 2021.

Exhibit A

Kayenta Landholdings – Proposed Reservoir on SITLA lands in crosshatches



10c

Kennecott OBA

BOARD MEMORANDUM

DATE: June 17, 2021

TO: Board of Trustees, Utah School & Institutional Trust Lands Administration (SITLA)

FROM: Tom Faddies, Assistant Director/Minerals
Jerry Mansfield, Resource Specialist

RE: Other Business Arrangement ("OBA") – Non-Competitive Lease of Metalliferous Minerals OBA.

LANDS:

<u>T2S, R2W, SLB&M</u>	<u>Salt Lake County</u>	<u>Fund</u>
Sec. 28: SW4	160.00 Acres	SM
<u>T3S, R3W, SL&M</u>	<u>Salt Lake County</u>	
Sec. 21: Lots 29(0.16), 30(0.20)	0.36 Acres	RES
<u>T3S, R3W, SLB&M</u>	<u>Tooele County</u>	
Sec. 28: Lots 19(25.82), 20(0.55)	26.37 Acres	RES
<u>T4S, R3W, SLB&M</u>	<u>Tooele County</u>	
Sec. 31: Lots 1(40.00), 2(40.00), 3(40.00)	120.00 Acres	SCH

Total Acreage: 306.73 Acres

APPLICANT: Kennecott Utah Copper LLC
4700 Daybreak Parkway
South Jordan, Utah 84009

As provided for under Utah Code Anno. 53C-2-401(1)(d)(ii), which permits the Board of Trustees to approve "other business arrangements", Kennecott Utah Copper, LLC. (Kennecott), on May 12, 2021, submitted a proposal to lease, under the metalliferous minerals lease category, the above-referenced land. The reason this action requires Board approval is the lease is not being offered via any competitive lease process, and the applicant is the only logical operator for the site.

Background

The proposed lands are split estate with State of Utah owning the mineral resources and Kennecott owning the surface estate. These lands are in the vicinity of the Bingham Canyon Mine and a lease on these parcels would package Kennecott's land holdings and allow them to confirm their mining plans for the Bingham Canyon Mine for their next twenty-year mine plan and would prevent nuisance lessees from interfering with Kennecott operations.

Kennecott proposes and the SITLA Mining Section recommends a bonus payment of $1,000 and that the lease for these lands to be issued on the SITLA's standard Metalliferous Minerals lease form and will include the following terms:

- The primary term of the leases will be ten (10) years.

- Annual rental on the standard lease is the greater of $1.00 per acre or $500.00.

- Lessee shall pay Lessor a production royalty on the basis of 8% of the gross value, for fissionable metalliferous minerals and 4% of the gross value for non-fissionable metalliferous minerals f.o.b. the mine.

- The lease will be extended beyond the 10-year primary term if in production or if the requirements for diligent development are satisfied.

- If the lease is extended beyond the primary term, beginning with the eleventh (11^{th}) lease year, the lessee will be required to pay an advanced minimum royalty in the amount of three (3) times the annual rent in addition to payment of the annual rent of $500. Annual rental and advanced minimum royalties can be credited against actual production royalties for the year in which production royalties accrue.

- $1,000 one-time bonus payment.

Respectfully Submitted by:

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Resource Specialist

10d
SITLA's Proposed Edits to Interim Order in EOG v SITLA

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BEFORE THE
UTAH SCHOOL AND INSTITUTIONAL TRUST LANDS ADMINISTRATION
BOARD OF TRUSTEES

EOG RESOURCES, INC., Petitioner, v. UTAH SCHOOL AND INSTITUTIONAL TRUST LANDS ADMINISTRATION, Respondent.	**SITLA'S PROPOSED EDITS TO THE HEARING EXAMINER'S PROPOSED FINDINGS OF FACT, CONCLUSIONS OF LAW AND FINAL ORDER**

Respondent Utah School and Institutional Trust Lands Administration ("SITLA"), pursuant to instructions given by the Board at the conclusion of the May 13, 2021 hearing, respectfully submits the following proposed changes to the draft Findings of Fact, Conclusions of Law and Order ("Proposed Order") submitted by the Board to the Hearing Examiner on April 20, 2021. Each of the proposed changes discussed on May 13th is set forth in a numbered paragraph below.[1] SITLA has spoken to EOG's counsel regarding the proposed changes below and EOG has approved of the form of the proposed changes.

1. Change the title within the caption of the Proposed Order to read: "Findings of Fact, Conclusions of Law and Interim Order Resolving Phase 1 Issues."

2. Remove the three paragraphs on Page 2 of the Proposed Order preceding the "Introduction" section. These three paragraphs begin with the phrases "The purpose of bifurcation…," "For these reasons," and "This Final Order." Additionally, remove the word "finally" on page 1, replace the word "Final" in "Final Order" on page 104 with the word "Interim", and remove the statement on page 104 regarding the right to seek immediate judicial review (the sentence begins: "An aggrieved party to this…").

3. Add a paragraph on page 74 immediately preceding Section VI., stating: "Further argument and analysis concerning the development and use of UCAs is appropriate in the 'recalculation' phase of this matter as this issue has not been the subject of significant briefing."

4. Add a numbered paragraph 3 on page 104 stating: "3. Pursuant to Rule R850-8-1500.2, and the January 9, 2019 Order Appointing Geoffrey Heath as Hearing Examiner, the Hearing Examiner is empowered to manage, and to the extent it aids progress in this matter, referee and issue interim recommendations concerning, the recalculation phase of this case as referenced in paragraph 2, above. The Hearing Examiner is further directed to work with the parties to develop a schedule for the recalculation phase of the proceedings that expedites, to the extent practical,

[1] At the May 13, 2021 hearing, the Board verbally instructed SITLA's counsel to prepare "the recommended edits" to the proposed Order. One of the edits SITLA had requested was a statement indicating that the Board's ruling regarding recoupment was limited to this case and not intended as guidance for other cases. EOG opposed that change, arguing that because the order will be treated as interim, that the matter should be reserved and not addressed at this time. Because the present order is interim and not final, the parties agree that the Board should resolve this issue in any final order.

resolution of this matter. The schedule should contemplate submission of the remaining dispute to the Hearing Examiner for decision within 90 days or such other time frame as the parties may determine is appropriate."

5. One further proposed change not addressed at the hearing is the correction of the starting date of the audit period in several locations of the Proposed Order. The starting date of the audit was January of 2007. The Proposed order on pages 1, 17 (¶ 89), 18 (two locations in ¶ 93), 28 (¶ 60), 99 (three locations), and 104 (¶ 2) references July of 2007 as the start date. This mistake likely resulted from SITLA's second audit report containing this same scrivener's error in a few locations (the date is stated correctly in other locations).

Respectfully submitted this 7th day of June, 2021.

SEAN D. REYES
UTAH ATTORNEY GENERAL

/s/ Michael S. Johnson
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CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing document was filed by email with lsjones@utah.gov, and served via email on the following, this 7th day of June, 2021:

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UTAH SCHOOL AND INSTITUTIONAL TRUST LANDS ADMINISTRATION
BOARD OF TRUSTEES

EOG RESOURCES, INC., **Petitioner,** **v.** **UTAH SCHOOL AND INSTITUTIONAL TRUST LANDS ADMINISTRATION, OFFICE OF THE DIRECTOR,** **Respondent.**	**FINDINGS OF FACT, CONCLUSIONS OF LAW AND INTERIM ORDER RESOLVING PHASE 1 ISSUES**

On August 22, 2018, under Utah Code Ann. § 53C-1-304(2)(a) and Utah Admin. Code R850-8-1000, EOG Resources, Inc. ("EOG") petitioned the School and Institutional Trust Lands Administration ("SITLA") Board of Trustees (the "Board") for review of an April 23, 2018 SITLA Audit Report (hereinafter the "2018 Audit Report"). The 2018 Audit Report assessed an estimated $2.2 million in additional royalties owed on natural gas produced from several state oil and gas leases in the Natural Buttes Field in eastern Utah of which EOG is the lessee. The 2018 Audit Report involves royalties on gas produced during the period from ~~July 1,~~ January of 2007 through December 31, 2017, as described more fully below. In its Petition for Review, EOG argued that it owes no additional royalty, and asserted it is entitled to a refund of approximately $743,000 in royalties that EOG claims it overpaid.

Under Utah Admin. Code R850-8-1100, the Board determined to conduct this matter as a formal adjudicative proceeding. Under section R850-8-1500.1, the Board appointed Geoffrey Heath as Hearing Examiner on January 9, 2019. Following submission of the administrative record compiled to date, opening briefs and reply briefs by the parties, and first and second stipulations of fact, a hearing on the legal issues was held on September 15, 2020. As a result of subsequent questions from the Hearing Examiner, the parties submitted a third stipulation of fact on November 6, 2020, and a fourth stipulation of fact on February 8, 2021.

The 2018 Audit Report and EOG's Petition for Review ("EOG Petition") raise a number of controlling issues of law, as well as potential disputed issues of fact. Resolution of controlling issues of law will determine which issues of fact are material to the ultimate outcome. Moreover, proper calculation of any additional royalties owed (or refunds due) depends on resolution of the underlying controlling legal issues. Therefore, the Hearing Examiner and the parties agreed that the most efficient course would be to bifurcate the proceeding. The Hearing Examiner and the parties agreed that this first phase of the proceeding should fully ~~and finally~~ resolve, on stipulated and undisputed facts, all issues of law that govern proper royalty calculation.

~~The purpose of bifurcation is to resolve controlling issues of law before conducting an evidentiary hearing on potentially disputed factual issues that are material to recalculation of royalties (or refunds) due under the legal rules determined in this Final Order. The intent of the parties and the Board is to avoid incurring the time and expense to conduct an extensive hearing and perform complex recalculations to arrive at a final dollar amount owed (if any), and then have to undertake that effort again in the event the Utah Court of Appeals or the Utah Supreme Court disagrees with the Board on one or more controlling issues of law. Once the controlling issues of law are determined with finality, the legal rules governing royalty calculation and resolution of potentially disputed material issues of fact will be established. The Board also believes that resolution of controlling legal issues also will increase the likelihood that the parties can agree on a recalculated number, and on calculation methodology going forward, without the necessity of a time-consuming and costly evidentiary hearing.~~

~~For these reasons, administrative decision-making has reached a stage where judicial review will advance and facilitate the orderly process of adjudication rather than disrupt it, for the reasons explained above. Further, this Final Order and decisions in any judicial review of this Final Order determine the legal rights and obligations of the parties, and legal consequences clearly flow from this Final Order. The issues of law resolved in this Final Order will not be relitigated or revisited in the second phase of this proceeding unless required by subsequent judicial review. Further, the legal determinations and rulings in this Final Order are not preliminary, preparatory, procedural, or intermediate with regard to subsequent agency action. Indeed, subsequent agency actionC*i.e.*, the second phase of this proceeding that involves recalculation of royalties and accounting questionsCdepends on legal determinations made in this Final Order.~~

~~This Final Order thus constitutes judicially reviewable "final agency action" within the meaning of the Utah Administrative Procedures Act, Utah Code Ann. §§ 63G-4-401 and 63G-4-403, under the standards applied in *Barker v. Utah Public Service Commission*, 970 P.2d 702, 705 (Utah 1998); *Union Pacific R.R. Co. v. Utah State Tax Commission*, 2000 UT 40, & 16, 999 P.2d 17, 21 (2000); and *Ameritemps, Inc. v. Labor Commission*, 2005 UT App. 491, 128 P.3d 31, 37-40 (2005), *affirmed*, 2007 UT 8, 152 P.3d 298 (2007). This Final Order therefore is appealable to the Utah Court of Appeals under Utah Code Ann. §§ 53C-1-304(5), 63G-4-401, and 63G-4-403.~~

INTRODUCTION

Before setting forth the Board's Findings of Fact and Conclusions of Law and supporting analysis, the Board believes it would be helpful to give a brief general summary of natural gas production operations, including an explanation of terminology used.[1] Natural gas consists

[1] For general reference, *see*, *e.g.*, https://www.eia.gov/energyexplained/natural-gas/; http://naturalgas.org/naturalgas/; http://naturalgas.org/naturalgas/extraction/; http://naturalgas.org/naturalgas/production/; http://naturalgas.org/naturalgas/processing-ng/; http://naturalgas.org/naturalgas/transport/; and https://en.wikipedia.org/wiki/Natural-gas_processing (and sources cited).

primarily of methane (CH_4). The thermal content of methane (measured in British Thermal Units, or "Btu") is very close to 1,000 Btu per cubic foot, or approximately one million Btu per thousand cubic feet (Mcf). Thus, gas volumes generally are expressed either in terms of Mcf or in terms of million Btu (MMBtu).

Much raw natural gas produced, as in the case of the gas involved in this appeal, contains heavier entrained liquid hydrocarbons such as ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}), pentane (C_5H_{12}) and continuing through a range of heavier hydrocarbons (C_6+). These entrained liquid hydrocarbons often are referred to as "natural gas liquids" (NGLs). These NGLs are valuable products when separated from the gas stream, and have much higher thermal content per unit of volume than methane. In addition, when more than very small amounts of NGLs are present in the gas stream, the Btu content of the gas is too high for it to be usable in most commercial, industrial, or residential applications unless the NGLs are separated out. Some gas streams also contain other valuable compounds or elements such as helium.

Separating out or extracting entrained valuable products from a raw gas stream generally is referred to as "processing" or "manufacturing".[2] Gas which has not been processed is referred to as "unprocessed gas," while gas which has been processed is referred to as "processed gas." The methane stream that results after NGLs or other products are extracted commonly is referred to as "residue gas." Gas may be sold as unprocessed gas before processing, or, as in the instant case, it may be sold after processing as processed gas, *i.e.*, as residue gas, with extracted NGLs or other products sold separately. The location of saleCwhere title is transferred to the purchaserCalso may vary. Sale may occur near the well, at another point on the lease or unit, or at locations such as transportation hubs or cities or industrial facilities far downstream after the gas is transported to those locations.

Almost all natural gas streams also contain other non-hydrocarbon compounds or impurities. Most frequently, these include hydrogen sulfide (H_2S) and water. Not infrequently, raw gas streams also contain some carbon dioxide (CO_2). Both H_2S and CO_2 will combine with water in the gas stream to form sulfuric acid (H_2SO_4) or carbonic acid (H_2CO_3), respectively. For that reason, these gases often are referred to as "acid gases." Both compounds, especially sulfuric acid, are corrosive to gas pipelines. Above certain levels, H_2S also is toxic. Consequently, gas pipelines will prescribe maximum levels of water and acid gases for the pipeline to accept gas for shipment. Most produced gas therefore must be treated to remove water (dehydration) and acid gases. Removal of acid gases commonly is referred to as "sweetening," or, with respect to H_2S, "desulphurization."

[2]As gas first surfaces at the wellhead of a producing well, it may also contain heavy hydrocarbons that will condense from the gas stream without processing. Generally speaking, gas coming from a wellhead will first go through a field separator. The liquid hydrocarbons coming from a separator generally are referred to as "condensate" or "field condensate," and are treated as crude oil. The terms of all the state leases involved here (section 1 of the older leases and section 4 of the newer leases) treat condensate as crude oil. Royalty on condensate is not at issue here, and was not part of the 2018 Audit Report that gave rise to this proceeding.

Natural gas surfaces at the wellhead at various pressures, which are determined by the pressure in the subterranean reservoir or structures from which the gas is produced. Various wells produce gas across a range of pressures. In some cases, the wellhead pressure is high enough for gas to enter a pipeline, but in most cases gas must be compressed to a pressure sufficient to enter the pipeline or pipelines that serve a particular producing field. In many cases, again depending on the wellhead pressure, it is necessary to compress gas to move it to a processing plant or treatment facility.

Because gas is produced from manyCsometimes hundredsCof wells in a particular producing field or area, it must be accumulated before it can be further treated or processed. Accumulation from numerous wells usually is referred to as “gathering” in this context, and is so referred to here. Gathering will be discussed further below.

Operations such as dehydration, sweetening, compression, and gathering are referred to here as “treatment.” “Treatment,” as that term is used here, does not yield valuable products extracted from a raw gas stream. “Processing,” as that term is used here, does.

Finally, with few exceptions, gas must be moved by pipeline to the destinations where it is used or consumed. That function commonly is referred to as “transportation,” and that term is used here in that sense. The relationship between gathering and transportation is discussed further in the legal analysis below. Compression also is necessary for transportation at various stages. The legal relationship between compression and transportation also is discussed below.

Unsurprisingly, the area covered by one or more subterranean deposits containing natural gas usually does not lie entirely within the geographic boundaries and ownership interests of the individual properties—usually oil and gas leases granted by the mineral estate owner—on which wells are drilled and from which the gas is produced. Deposits that will yield sufficient production to be profitable will vary in size and shape, and in the majority of situations will overlap lease boundaries. Thus, while there is production from some “stand-alone” leases, in the majority of circumstances, such as in the area in eastern Utah involved here, properties adjacent to or in the near vicinity of each other will be developed under a cooperative arrangement. The purpose of doing so is to prevent different lessees from drilling too many wells into a particular reservoir and thereby damaging the reservoir and its production potential.

The cooperative arrangement to which some of EOG’s leases are committed is known as unitization. Four of the seven state oil and gas leases involved in this proceeding are committed to units (three leases in one unit and a fourth lease in a second unit), as set forth more fully below. In *Amoco Production Co. v. Heimann*, 904 F.2d 1405, 1410-1411 (10th Cir. 1990), the United States Court of Appeals for the Tenth Circuit concisely explained unitization as follows:

> Unitization refers to the consolidation of mineral or leasehold interests in oil or gas covering a common source of supply. Unitization resulted from state legislatures’ efforts to modify the rule of capture which had previously been applied to oil and gas law. The goals of unitization are conserving resources by preventing waste and protecting landowners’ correlative rights.

> Following unitization of an oil field, the royalty clause of an oil and gas lease generally is modified and the lessor becomes entitled to a royalty based on a pro rata share of the production attributable to its land, regardless of whether production is from that land or another tract included within the unit. The working interest owners' share is based on a participation formula calculated from geological, physical and economic data. . . . [T]he most frequently employed basis for allocating unitized production is surface acreage . . . . [Citations and footnotes omitted.]

Because the two units involved in this proceeding include (and consist primarily of) Federal oil and gas leases, the unit agreements are Bureau of Land Management (BLM)-prescribed forms under the authority of the Mineral Leasing Act at 30 U.S.C. ' 226(m) and 43 C.F.R. Part 3180 or predecessor regulations. The unit agreements supersede the terms of individual leases in some respects which, as relevant to this proceeding, are discussed further below. The unit agreement allocates production from wells within the unit to the leases or properties which comprise the unit. In addition, more than one producing subterranean reservoir may lie within the boundaries of a unit. For example, there may be different reservoirs at different depth ranges. In this event, the unit agreement will designate separate "participating areas" and allocate the production from each participating area to the leases or properties within whose boundaries the participating area lies.

FINDINGS OF FACT

The Findings of Fact which follow are drawn from the administrative record, the parties' four factual stipulations, and undisputed facts of public record.[3]

I. The Leases, Field, and Units Involved in This Proceeding

1. The State of Utah, acting through SITLA, is the lessor of a number of state oil and gas leases in the Natural Buttes Field in Eastern Utah. The Natural Buttes Field is designated by the Utah Division of Oil, Gas, and Mining (formerly the Utah Oil and Gas Conservation Commission). *See* map of Natural Buttes Field at Administrative Record Appendix (APP) 000505.

2. EOG is the lessee of the seven state oil and gas leases at issue in this matter, namely, Mineral Lease No. (ML) 1299, ML 3077, ML 3078, ML 3355, ML 45681, ML 47045, and ML

[3] The majority of the stipulated facts concerning the production, movement, treatment, processing, handling, and sales of gas in Parts II and III of these Findings of Fact below are from information in EOG's possession. SITLA knows of no reason to, and does not, question the accuracy of those facts. However, if discovery proceeds in the second phase of this proceeding regarding proper accounting of revenues and deductions, allocation of costs, allocation of production volumes, and calculation of royalty value under the legal analysis and conclusions of law set forth below, it is possible that such discovery could further refine factual findings relevant to those calculations. This decision does not preclude such further factual development.

48380 (collectively, the "subject leases"). All of the subject leases are producing oil and gas or have unit production allocated to the lease. All of the subject leases produced oil and gas or had unit production allocated to the lease during the period relevant to this proceeding.

3. ML 1299 originally was issued to Belco Petroleum Corporation on January 2, 1953. The lease covers 40 acres described as SE1/4NE1/4 Section 7, T 9 S, R 22 E, S.L.M. APP 000011.

4. ML 1299 is part of the Stagecoach Unit, and was part of the Stagecoach Unit throughout the period relevant to this proceeding. The Stagecoach Unit also includes four Federal oil and gas leases and some unleased Federal mineral estate.[4] EOG is, and was throughout the relevant period, the lessee of ML 1299 and the operator of the Stagecoach Unit.

5. BLM approved the Stagecoach Unit Agreement in 1960. APP 000095. SITLA likewise approved the unit agreement through its Approval-Certification-Determination. The Stagecoach Unit has been contracted over time, and continues to produce oil and gas.

6. ML 1299 is within two participating areas (PAs) in the Stagecoach Unit, namely, the Initial Wasatch PA and the Consolidated Mesaverde/Mancos PA, as revised. APP 000503. The parties do not dispute the production allocation under the Stagecoach Unit participating areas.

7. There are no wells located on lease ML 1299. APP 000094. A portion of the production from the unit participating areas was allocated to that lease.

8. ML 3077 originally was issued to Continental Oil Company on January 2, 1953. The lease covers 640 acres described as Section 2, T 9 S, R 22 E, S.L.M. APP 000019.

9. ML 3078 originally was issued to Continental Oil Company on January 2, 1953. The lease covers 640 acres described as Section 16, T 9 S, R 22 E, S.L.M. APP 000025.

10. ML 3355 originally was issued to Shell Oil Company on January 2, 1953. The lease covers 640 acres described as Section 32, T 9 S, R 23 E, S.L.M. APP 000029.

11. ML 3077, ML 3078, and ML 3355 are part of the Chapita Wells Unit, and were part of the Chapita Wells Unit throughout the period relevant to this proceeding. The Chapita Wells Unit also includes 28 Federal oil and gas leases covering tracts of various sizes.[5] EOG is, and was throughout the relevant period, the lessee of ML 3077, ML 3078, and ML 3355, and the operator of the Chapita Wells Unit.

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[4] https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/utah/agreement-maps (download UT_OandG_Stagecoach_Map.pdf); APP 000503.

[5] https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/utah/agreement-maps (download UT_OandG_Chapita Wells_Map.pdf); APP 000504.

12. BLM approved the Chapita Wells Unit Agreement (APP 000072) in 1951. SITLA likewise approved the unit agreement through its Approval-Certification-Determination. The Chapita Wells Unit has been contracted and expanded over time, and continues to produce oil and gas.

13. ML 3077, ML 3078, and ML 3355 in the Chapita Wells Unit are within and producing from two participating areas, namely, the Consolidated Wasatch PA and Consolidated Mesaverde PA, as revised. APP 000504. The parties do not dispute the production allocation under the Chapita Wells Unit participating areas.

14. ML 45681 originally was issued to Continental Marketing on August 10, 1992. The lease covers a total of 80 acres in two 40-acre parcels (in relative proximity to but not adjacent to each other) described as NE1/4SE1/4 Section 6 and NW1/4NE1/4 Section 7, T 9 S, R 22 E, S.L.M. APP 000034. ML 45681 is not part of a unit. The southern of the two parcels of this lease borders the Stagecoach Unit on the north. APP 000503. EOG is, and was throughout the relevant period, the lessee and operator of ML 45681.

15. ML 47045 originally was issued to Samuel Butler, III on September 6, 1995. The lease covers 640 acres described as Section 16, T 9 S, R 23 E, S.L.M. APP 000047. Although it borders the eastern portion of the Chapita Wells Unit on the north, ML 47045 is not part of a unit. APP 000504. EOG is, and was throughout the relevant period, the lessee and operator of ML 47045.

16. The Natural Buttes Field encompasses several other units in addition to the Chapita Wells Unit and the Stagecoach Unit, as well as non-unitized areas. Other units in the Natural Buttes Field within which state oil and gas leases are located include the Natural Buttes Unit, the Maverick Unit, the River Bend Unit, the Hill Creek Unit, the Duck Creek (Green River) Unit, the Island Unit, and the Ponderosa Unit.[6] None of these units are involved in this proceeding. EOG does not operate any of these units.[7] The Natural Buttes Field also includes units within which Federal leases are located but in which no state leases are located, including the Badlands Unit, the White River Unit, and the North Alger Unit. *Id*.[8]

[6] *See* map at https://datamining.ogm.utah.gov/.

[7] Kerr-McGee is operator of the Natural Buttes Unit (https://reports.blm.gov/report/LR2000/64/Pub-CR-Serial-Register-Page for UTU 063047X). Kerr McGee O & G Onshore LP is operator of the Maverick Unit (*id.*, Serial Register Page for UTU 088574X) and the Ponderosa Unit (*id*., Serial Register Page for UTU 088209X). XTO Energy, Inc is operator of the River Bend Unit (*id*., Serial Register Page for UTU 063054X) and the Hill Creek Unit (*id*., Serial Register Page for UTU 076784X). Wexpro Co. is the operator of the Island Unit (*id*., Serial Register Page for UTU 063026X). Finley Resources, Inc., is the operator of the Duck Creek Unit (*id*., Serial Register Page for UTU 072689A).

[8] EOG is the operator of the Badlands Unit (https://reports.blm.gov/report/LR2000/64/Pub-CR-Serial-Register-Page for UTU 060917X). Middle Fork Energy LLC is the operator of the White River Unit (https://reports.blm.gov/report/LR2000/64/Pub-CR-Serial-Register-Page for UTU 063021X). Wapiti Rocky Mountain LLC is the operator of the North Alger Unit

17. ML 48380 originally was issued to Craig L. Emmanuel on January 26, 2000. The lease covers 600 acres described as E1/2, N1/2SW1/4, SE1/4SW1/4, and NW1/4 of Section 32, T 10 S, R 18 E, S.L.M. APP 000059. In other words, ML 48380 comprises all of Section 32 except for the SW1/4SW1/4. ML 48380 is the only lease involved in this proceeding that is not within the Natural Buttes Field. It is located several miles to the west (and across the Green River from) the western portion of the Natural Buttes Field. ML 48380 is not part of a unit, but encompasses a small part of the Uteland Butte Field that is not contiguous with other parts of that field. APP 000506. EOG was the lessee and operator of ML 48380.

18. A map showing the location of the subject leases and units, other units in the Natural Buttes Field and surrounding areas, well sites, and topographic features in relief is in the Administrative Record at APP 000507 (EOG_Audit_OilGas_Leases_Wells_36x48_Leases.pdf). A map showing the general location of the leases, the unit boundaries, the participating areas, and the location of various wells, pipelines and processing facilities is found at APP 000094. *See also* Administrative Record, Chapita Map2.

II. <u>Production, Movement, Treatment, and Processing of Gas Produced</u>

A. Facilities Involved in Collection, Compression, Treatment, Processing, and Transportation of Gas Produced from the Subject Leases and Units

1. Gathering Lines and Related Facilities

19. The primary owner/operator of the lines through which gas produced from wells on the subject leases and units during the relevant period was gathered before processing was QEP Field Services, a wholly-owned subsidiary of QEP Resources. Third Stipulated Statement of Facts as of November 6, 2020 (hereinafter "Third Stipulation"), p. 4.[9]

20. QEP Resources was spun off from Questar Corp. as an independent entity in 2010. http://www.qepres.com/about/history/. EOG is unrelated to QEP Resources and to QEP Resources' Questar subsidiary predecessors. EOG's contracts with these entities for gas gathering services therefore were arm's-length contracts.[10]

(https://reports.blm.gov/report/LR2000/64/Pub-CR-Serial-Register-Page for UTU 063094X).

[9] QEP Field Services was acquired by Tesoro Logistics LP in December 2014. APP 000407; APP 000492; APP 000436. Tesoro Logistics LP became Andeavor Logistics, LP on August 1, 2017, a few months from the end of the relevant period. https://www.oilandgas360.com/tesoro-corporation-and-tesoro-logistics-lp-become-andeavor-and-andeavor-logistics-lp/; *see* APP 000408-000411; APP 000496-000501; APP 000442-000447. However, the acquisition and subsequent changes are not material to, and do not affect, the analysis and resolution of this matter. References to QEP Field Services include references to its Questar subsidiary predecessor entities and to Tesoro after December 2014 and to Andeavor after August 1, 2017.

[10] *See, e.g.*, APP 00333-000342; APP 000232-000244; APP 000373-000392; APP 000367-000372; APP 000401-000403; APP 000400; APP 000393-000398; APP 000245-000264; APP

21. The Davies Road Central Facility is located in Section 33, T 9 S, R 23 E, S.L.M., within the Chapita Wells Unit and in the section immediately to the east of ML 3355. The Davies Road Central Facility was installed in 2014. APP 000094; Second Stipulated Statement of Facts as of June 25, 2020 (hereinafter "Second Stipulation"), pp. 5-6, & 17.

22. The East Chapita Wells (ECW) Section 16 Central Facility is located on ML 47045, which, as noted above, encompasses Section 16, T 9 S, R 23 E, S.L.M. The ECW Section 16 Central Facility was installed in 2013. APP 000094; Second Stipulation, pp. 5-6, & 17.

2. Dehydrators

23. In almost all instances, a dehydration unit was located at each well site and dehydration occurred on the lease before gas entered the gathering system. EOG or QEP Field Services owned and operated the dehydration equipment, and QEP Field Services charged for its dehydration services under the gathering services contracts. Second Stipulation, p. 5, & 17; APP 000333-000335; APP 000245, 000248.

24. The gathering services contracts also provided for a portion of EOG's gas to be used as fuel in the gathering and dehydration operations. *Id*.; *see also* APP 000393.

25. After installation of the Davies Road Central Facility in 2014, gas produced from wells on ML 3355 and adjacent and nearby Federal leases was dehydrated at that facility. Second Stipulation, p. 6, & 17. This gas also was measured at that facility. Stipulated Statement of Facts as of August 8, 2019 (hereinafter "First Stipulation"), p. 4, & 19.

26. After installation of the ECW Section 16 Central Facility in 2013, gas produced from wells on ML 47045 was dehydrated at that facility. Second Stipulation, p. 6, & 17.

27. Beginning no later than September 2015, some dehydration may have been performed at the Stagecoach and Iron Horse processing plants described below. APP 000494-000495.

3. Compressors

28. As described below, all of the compressor facilities at which EOG's gas was compressed were owned and operated by unrelated third parties throughout the relevant period. EOG's contracts for compression services therefore were arm's-length contracts.[11]

29. The compression services contracts provided for fees for compression services and for a portion of EOG's gas to be used as fuel in compression operations.

000266-000277; APP 000278-000291; APP 000292-000313; and APP 000502.

[11] *See, e.g.*, APP 000232-000244; APP 000245-000264; APP 000265; APP 000266-000277; and APP 000292-000313.

30. The Chapita compressor station is located in Section 15, T 9 S, R 22 E, S.L.M., within the Chapita Wells Unit in the section immediately to the east of ML 3078. APP 000094. QEP Field Services was the owner and operator of the Chapita compressor station during the relevant period. Second Stipulation, p. 5 & 16; Third Stipulation, p. 4.

31. The inlet pressure at the Chapita compressor station generally is in the range of 135-150 pounds per square inch-gauge (psig), with rare variances up to a maximum of 261 psig. Discharge pressure at the Chapita compressor station is approximately 400 psig. Second Stipulation, p. 4, & 13(f); APP 000170-000181; APP 000232.

32. The Coyote compressor station, also known as the Coyote Wash compressor station, is located on ML 3078 (Section 16, T 9 S, R 22 E, S.L.M.), east of the Stagecoach and Iron Horse processing plants described below. APP 000094. QEP Field Services was the owner and operator of the Coyote compressor station during the relevant period. https://19january2017snapshot.epa.gov/sites/production/files/2015-07/documents/ qepfieldservicescoyotewashcsfinalp71permitv-uo-000015-2006.00.pdf, p. 1 (p. 10 of 78 of the linked document).

33. Up to nine compressor units operated at the Coyote compressor station. The Chapita compressor station fed the Coyote C-100 and C-200 units. The discharge pressure from one of these two units at the Coyote compressor station is approximately 960 psig. The discharge pressure from the other is 1,100 psig. Third Stipulation, pp. 6-7; Second Stipulation, p. 4, & 13(d); APP 000265.

34. The other seven compressor units at the Coyote compressor station took gas produced from wells in the Chapita Well Unit and other wells in the surrounding area through all stages of compression, with an average inlet pressure of approximately 143 psig to a discharge pressure of approximately 1,100 psig. Third Stipulation, pp. 6-7; Second Stipulation, & 13(d).

35. The Fidlar compressor station is located on ML 3078, a short distance north of the Stagecoach and Iron Horse processing plants described below. APP 000094. The Fidlar compressor station is located at an inlet to the Questar Pipeline. Questar Pipeline Company, a subsidiary of Questar Corp., owned and operated the Fidlar compressor station and the Questar Pipeline. Third Stipulation, p. 6.[12]

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[12] Questar Corp. was acquired by Dominion Energy in 2016 toward the end of the relevant period, and the subsidiaries' names have changed. *See* https://news.dominionenergy.com/ 2016-09-16-Dominion-Resources-Combines-With-Questar-Corporation. However, the acquisition by Dominion is not material to, and does not affect, the analysis and resolution of this matter. Because Questar was the relevant entity during most of the relevant period, this Order will continue to refer to Questar here for simplicity. References to Questar include references to Dominion and relevant subsidiaries after the date of acquisition.

4. Desulphurization Facilities

36. As necessary, gas produced from the subject leases and units was treated to remove H_2S to meet the quality specifications in the contract with the gathering system. Initially, treatment occurred at the well sites. Later, some central H_2S towers were installed to treat troubled areas of the field, but much of the treatment still occurred at the well site. Second Stipulation, p. 6, & 18.

37. Under EOG's gathering and compression contract with QEP Resources' predecessor, gas delivered to the gathering system had to meet the quality requirements for sulfur content of the Questar pipeline. APP 000245, 000252.

5. Processing Plants

38. All of the gas processing plants at which gas produced from EOG's state leases, and from Federal leases in the Chapita Wells Unit and the Stagecoach Unit, was processed were owned and operated by unrelated third parties throughout the relevant period. Second Stipulation, p. 5 && 14, 16. EOG's contracts for processing services therefore were arm's-length contracts.

39. The Red Wash processing plant, also known as the 24B or Redwash 24B plant, was the first processing plant in service. It is located in T 7 S, R 23 E, S.L.M., in the Red Wash Field northeast of the Natural Buttes Field and the Chapita Wells and Stagecoach Units. Third Stipulation, p. 4; APP 000506. The Red Wash plant was in service in or before 1997. https://geology.utah.gov/docs/statistics/naturalgas4.0/pdf/T4.11.pdf (p. 18 of 18).

40. EOG's processing contract with QEP Field Services' predecessor Questar subsidiary, entered into in January 2005, is at APP 000469-000480.

41. The Red Wash plant uses refrigeration methods to process gas. The other plants described below came on line to handle increased production as the drilling program progressed. Third Stipulation, p. 4.

42. The Red Wash plant uses a portion of EOG's gas as fuel to operate the plant, including processing, dehydration, and compression. APP 000470 (& 1.11), 000471 (& 2.4).

43. The processing contract for the Red Wash plant requires EOG to pay specified processing fees. APP 000475, 000482.

44. The Stagecoach processing plant and the Iron Horse processing plant are located in the same fenced parcel in Section 16, T 9 S R 22 E, on the western edge of ML 3078 and the western edge of the Chapita Wells Unit. The western edge of the Chapita Wells Unit is also the boundary with the Stagecoach Unit. APP 000094; Third Stipulation, pp. 3, 4.

45. QEP Field Services owned and operated the Stagecoach and Iron Horse plants. Third Stipulation, p. 4; Second Stipulation, p. 5, & 16.

46. The Stagecoach plant began service on September 1, 2008. APP 000489. While the Stagecoach plant was under construction, processing at the Stagecoach plant was added to EOG's contract for processing at the Red Wash plant through a July 12, 2007 amendment to the contract. APP 000481-000484.

47. The Stagecoach plant processes gas using refrigeration methods. Third Stipulation, p. 4.

48. The Stagecoach plant uses a portion of EOG's gas as fuel to operate the plant, including processing, dehydration, and compression. APP 000470 (& 1.11), 000471 (& 2.4).

49. The processing contract for the Stagecoach plant requires EOG to pay specified processing fees. APP 000482; APP 000437-000438; APP 000494-000495.

50. Construction of the Iron Horse plant began in 2010, and the plant began service on January 19, 2011. APP 000431. EOG's contract for processing at the Iron Horse plant, entered into on March 17, 2010, between EOG and QEP Field Services' predecessor Questar subsidiary, is at APP 000414-000425.

51. The Iron Horse plant processes gas using cryogenic methods, which result in extraction of greater quantities of NGLs than plants that use refrigeration processes. Third Stipulation, p. 4; APP 000414, 000417.

52. The Iron Horse plant uses a portion of EOG's gas as fuel to operate the plant, including processing, dehydration, and compression. APP 000415 (& 1.13), 000416 (& 2.4).

53. The processing contract for the Iron Horse plant requires EOG to pay specified processing fees. APP 000420; APP 000437-000438; APP 000494-000495.

54. Most of the production during the relevant period was processed through the Iron Horse and Stagecoach plants. After it came into service, the Iron Horse plant was the preferred and primarily used plant, and the Stagecoach and Red Wash plants became essentially overflow plants. Third Stipulation, p. 4; Fourth Stipulated Statement of Facts as of January 15, 2021 (hereinafter "Fourth Stipulation"), p. 4.

55. The Chipeta processing plant is located in the Chapita Wells Unit in Section 15, T 9 S, R 22 E, S.L.M. (the section immediately to the east of ML 3078). Third Stipulation, p. 3; APP 000506. The Chipeta plant began service in June 2009. APP 000182.

56. EOG's contract for gas processing at the Chipeta plant, dated December 10, 2009, and amended on September 22, 2010, is at APP 000182-000200.

57. The Chipeta plant processes gas using cryogenic methods. During the relevant period, Anadarko Petroleum Corp. (through its ownership interest in Chipeta Processing, LLC) was a part owner of the Chipeta plant. Second Stipulation, p. 5, & 16; Third Stipulation, pp. 3-4;

see also https://www.sec.gov/Archives/edgar/data/1414475/000095012309061881/h68599exv10w4.htm; and https://19january2017snapshot.epa.gov/sites/production/files/2015-07/documents/chipetaprocess-chipetagasplantfinalinitialpermit-v-uo-00023-2009.00.pdf, p. 1 (p. 8 of 219 of the linked document).

58. The Chipeta plant uses a portion of EOG's gas as fuel to operate the plant, including processing, dehydration, and compression. APP 000183, 000186-000187.

59. The processing contract for the Chipeta plant requires EOG to pay specified processing fees. APP 000182 .

60. During part of the relevant period, Anadarko Petroleum Corp. and its subsidiary Kerr-McGee Oil and Gas Onshore LP were partial working interest owners in some of the wells in the Chapita Wells Unit. EOG ultimately bought out most of Anadarko's interest in late 2012. Third Stipulation, p. 5; APP 000358-000364; APP 000343-000357.

61. The flow through the Chipeta plant was relatively small, and consisted of Anadarko's portion of the gas produced from wells in which Anadarko was a co-working interest owner. Third Stipulation, pp. 4-5.

6. Pipelines

62. All residue gas produced from or allocated to the subject state leases and sold during the relevant audit period was delivered into the Questar pipeline. Second Stipulation, p. 3, & 11.

63. The minimum pressure required for gas to enter the Questar pipeline is approximately 950 psig, with a maximum limit of 1,440 psig. Second Stipulation, pp. 4-5, & 13(g).

64. To be accepted by the pipeline, among other requirements, residue gas could contain no more than 1/4 grain of H_2S per 100 cubic feet, no more than 5 grains of total sulfur per Mcf, and no more than 5 pounds of water per million cubic feet. *See* Dominion Energy Questar Pipeline, LLC, FERC Gas Tariff, August 31, 2010, Part 1, section 13.1(b), (h), and (i), APP 000154-000155, 000160.

65. The Questar pipeline transports residue gas produced from or allocated to the subject state leases to various points of downstream delivery. The primary point of delivery was the Kern River terminal near Goshen, Utah. EOG's transportation contracts with the Questar pipeline were arm's-length contracts. Second Stipulation, p. 3, & 11; APP 000449-000468; Fourth Stipulation, pp. 6-7.

66. Compressors are located at points along the Questar pipeline downstream of the pipeline inlet at the Fidlar compressor station between the Fidlar compressor station and the Kern River terminal, specifically, at Blind Canyon, Oak Spring, and Thistle. Fourth Stipulation, Maps 2 and 3.

B. Handling of Production from or Allocated to the Subject State Leases

67. The wellhead pressure of gas produced from leases in the Chapita Wells Unit and the Stagecoach Unit ranged between approximately 135 and 190 psig. Second Stipulation, pp. 3-4, & 13(a). Examples are shown in the wellhead chromatographic gas sample analyses at APP 000162-000165 (see the line entry for "Line Pressure").

68. The wellhead pressures in the subject portions of the Natural Buttes Field did not change considerably during the audit period. Most pressure differences among the wells can be attributed to the amount of gas being produced into the system (related to drilling activity and well decline), restrictions in the infrastructure, and the well's physical location relative to the compressor stations. Second Stipulation, p. 3, & 12.

69. Production from ML 3077 and ML 3078 and other adjacent and nearby Federal leases in the Chapita Wells Unit was measured at facility measurement points (FMPs) located at the well. First Stipulation, p. 4, & 19.

70. Production from ML 3077 and ML 3078 and other adjacent and nearby Federal leases in the Chapita Wells Unit then moved to either (1) the Chapita compressor station, and from there to the Coyote compressor station, or (2) directly to the Coyote compressor station. Third Stipulation, pp. 5-7.

71. Before completion of the Davies Road Central Facility in 2014, production from wells on ML 3355 and numerous other wells on adjacent and nearby Federal leases in the southeastern portion of the Chapita Wells Unit was measured at FMPs located at the well. After the Davies Road Central Facility began operation, production from these wells was measured at the FMP at that facility. First Stipulation, p. 4, & 19; Second Stipulation, p. 5, & 17; APP 000094.

72. Gas then moved from the Davies Road Central Facility to the Chapita compressor station, and from there to the Coyote compressor station. First Stipulation, p. 4, & 19; Third Stipulation, pp. 5-7.

73. Production allocated to ML 1299 in the Stagecoach Unit was measured at FMPs located at the well. Gas then moved to either the Chapita compressor station (and from there to the Coyote compressor station) or directly to the Coyote compressor station. Third Stipulation, pp. 5-7; Administrative Record, Chapita Map2.

74. Production from the non-unitized ML 45681 (the two non-contiguous parcels situated immediately north of the Stagecoach Unit) was measured at an off-lease FMP at the entrance to the Lateral 0 line, because ML 45681 is located in a flood plain. An FMP therefore could not be installed on the lease. First Stipulation, p. 5, & 23.

75. There is only one well on ML 45681. Gas produced from ML 45681 then flowed to the Coyote compressor station. Administrative Record, Chapita Map2; APP 000094.

76. Before completion of the ECW Section 16 Central Facility in 2013, production from non-unitized ML 47045, situated immediately to the north of the southeastern portion of the Chapita Wells Unit, was measured at FMPs at the well. After the ECW Section 16 Central Facility began operation, production from ML 47045 was measured at that facility. First Stipulation, p. 5, & 24; Second Stipulation pp. 5-6, & 17.

77. Gas produced from ML 47045 then moved to the Chapita compressor station, and from there to the Coyote compressor station. First Stipulation, p. 5, & 24; Third Stipulation, pp. 5-7.

78. Early in the relevant period, gas compressed at the Coyote compressor station then moved to the Red Wash plant for processing. After processing, residue gas was moved back to the Fidlar compressor station through a line known as Line 59, and into the Questar pipeline for transportation to downstream markets. Second Stipulation, p. 5, & 14; Third Stipulation, pp. 4, 6; Fourth Stipulation, p. 4.

79. After the Stagecoach, Chipeta, and Iron Horse processing plants, respectively, came into service, gas moved from the Coyote compressor station to the Stagecoach, Iron Horse, or Chipeta plant for processing, except for small volumes of overflow production after the Stagecoach plant began operation that was processed at the Red Wash plant. Second Stipulation, p. 5, & 14; Third Stipulation, pp. 4-5; Fourth Stipulation, p. 4.

80. From the Iron Horse, Stagecoach, or Chipeta processing plant, residue gas moved into Line 59 to the Fidlar compressor station and into the Questar pipeline for transportation to downstream markets. Third Stipulation, pp. 5-7; Fourth Stipulation, p. 4; Administrative Record, Chapita Map2.

81. Production from non-unitized ML 48380 (the lease not within the Natural Buttes Field) was measured at an FMP at the well. The gas then flowed directly into the Questar pipeline at the West Desert Tap at a line pressure of 480 psig. No treatment or processing operations were performed on this gas. EOG assigned the single well on this lease, the State 1-32, to a third party in 2012. First Stipulation, p. 5, & 25; Second Stipulation, p. 5, & 15; APP 000094, Inset B; APP 000161.

82. The West Desert Tap is off the lease, and is situated many miles downstream of the Fidlar compressor station and several miles upstream of the Blind Canyon compressor station in Duchesne County. APP 000094, Inset B; Fourth Stipulation, Map 2.

III. <u>Gas Sales</u>

83. All residue gas produced within a unit which included both Federal and State leases was commingled and sold under a series of contracts during the entirety of the relevant period. Second Stipulation, p. 2, & 7.

84. During the audit period, EOG sold residue gas to one or more purchasers under one or more contracts in effect at a given time. Second Stipulation, p. 2, & 8.

85. All residue gas produced from or allocated to the State leases within the Chapita Wells Unit and the Stagecoach Unit was sold under the same contracts as gas produced from or allocated to the Federal leases within those units, with all production being commingled prior to sale. Second Stipulation, p. 3, & 9.

86. EOG was the only operator selling gas produced from the subject leases and units during the relevant period. However, some minority working interest owners who were not operators took their share of gas in kind and presumably sold it on their own. EOG does not have copies of those contracts and is not aware of the terms of such sales. Second Stipulation, p. 3, & 10.

87. All residue gas produced and sold during the relevant audit period was delivered into the Questar pipeline at the inlet at the Fidlar compressor station. All residue gas produced and sold was delivered and sold downstream of the inlet of the Questar pipeline. No purchasers took delivery of residue gas at the inlet of the Questar pipeline. Second Stipulation, p. 3, & 11; Fourth Stipulation, p. 4.

88. NGLs extracted by processing at the Red Wash, Stagecoach, and Iron Horse plants were sold to QEP at the plant for a price computed under a formula prescribed in the processing contract. NGLs extracted by processing at the Chipeta plant were sold to Chipeta Processing, LLC, at the plant for a price computed under a formula prescribed in the processing contract. *See* APP 000475; APP 000482; APP 000182; APP 000420, APP 000426-000427.

IV. <u>The SITLA Audits and Order</u>

89. SITLA audited EOG's royalty payments on gas produced from or allocated to the subject leases for the period of ~~July 1,~~ <u>January of</u> 2007, through December 31, 2011, and issued its audit report on August 1, 2012 ("2012 Audit Report"). A copy of the 2012 Audit Report is at APP 000001-000005. First Stipulation, p. 2, & 2.

90. The 2012 Audit Report asserted that EOG had improperly classified as deductible costs of transportation the costs of certain treatment and gathering functions that were necessary to put gas into marketable condition. *Id*.

91. The 2012 Audit Report asserted that EOG owed additional royalty of $674,083, plus interest through July 2012 of $146,037, for a total amount of $820,120. *Id*.

92. The 2012 Audit Report ordered EOG to do the following:

> **If you do not agree with this assessment, submit evidence in writing to support your position or schedule a meeting with us to discuss your position within 60 days of receipt of this letter.** After your response has been reviewed, we will issue our final

assessment. If you do not request a conference or provide information to support any disagreements with this notice, the amount stated above is due within 60 days from the date you receive this notice.

Id., p. 4 (boldface emphasis in original).

93. Following discussions between EOG and SITLA in which EOG indicated it would amend its royalty reports, the audit for the period ~~July 1,~~ January of 2007, through December 31, 2011, was not concluded. APP 000010. Consequently, the original audit period was incorporated into an audit for the period January 1, 2012, through December 31, 2017. SITLA issued the 2018 Audit Report on April 23, 2018, for the entire period ~~July 1,~~ January of 2007, through December 31, 2017. A copy of the 2018 Audit Report is at APP 000006-000010. First Stipulation, p. 2, & 3.

94. The 2018 Audit Report asserted that EOG had (1) improperly deducted gathering and other costs of treating production to put it in marketable condition; (2) improperly deducted transportation costs for residue gas in excess of 50 percent of the value of the residue gas; (3) failed to verify whether processing allowance deductions for gas processed through the Chipeta plant exceeded two-thirds of the proceeds derived from sales of the NGLs extracted at that plant; (4) improperly failed to account for residue gas used as fuel during transportation through the Questar pipeline; and (5) failed to pay royalty on production taken in kind from one well by a co-working interest owner who had not paid royalty. *Id*.

95. The 2018 Audit Report asserted that EOG owed an estimated $2.2 million in unpaid royalties. *Id*.

96. The 2018 Audit Report ordered EOG to do the following:

> If EOG agrees with our findings, they [*sic*] have the option to pay the $2.2 million within 45 days of receiving this letter closing out EOG's royalty obligations for the time period January 1, 2007 through December 31, 2017 or amend their [*sic*] royalty reports going back to 2007 correcting the errors listed above in a timely manner.
>
> . . . .
>
> **If EOG does not agree with our assessment, submit evidence in writing to support your position or schedule a meeting with us to discuss your position within 45 days of receipt of this letter.** After your response has been reviewed, we will issue our final assessment. If you do not request a conference or provide information to support any disagreements with this notice, the amount stated above, or an agreement to amend reports needs to be completed within 45 days from the date you receive this notice.

Id., pp. 4-5 (boldface emphasis in original).

97. On August 22, 2018, EOG petitioned the SITLA Board of Trustees for review of the 2018 Audit Report. EOG's petition asked the Board to set aside the 2018 Audit Report findings and assessment in full, and to remand to SITLA with instructions to refund allegedly overpaid royalties in the amount of $743,000.

98. On October 31, 2018, SITLA filed its response to EOG's petition. SITLA's response denies that EOG is entitled to the relief requested, including any refund.

CONCLUSIONS OF LAW

Based on the foregoing findings of fact and the legal analysis which follows below, the Board enters the following conclusions of law:

I. Lease Terms

A. The "Value at the Well" Royalty Obligation and the Federal Floor Proviso

1. The gas royalty clause in section 4(b) of each of the subject lease instruments (quoted below) requires the lessee to pay a royalty of 12½ percent "of the reasonable market value at the well of all gas produced and saved or sold from the leased premises." The quoted language is referred to hereinafter as the "value at the well provision."

2. Under the value at the well provision, gas becomes royalty-bearing when it leaves the lease if the lease is not part of a unit.

3. If the lease is part of a unit, EOG owes royalty to the State on the portion of the volumes produced from the respective unit participating areas that is allocated to each of the unitized state leases. Gas produced from the unit participating areas that is allocated to a unitized state lease becomes royalty-bearing when the gas leaves the unit.

4. The gas royalty clause in section 4(b) of the lease instruments further provides that if the gas is sold under a contract that the lessor has approved in whole or conditionally, the reasonable market value for royalty purposes shall be the price at which the production is sold, then adding the following: "provided that in no event shall the price for gas be less than that received by the United States of America for its royalties from gas of like grade and quality from the same field." The quoted language is referred to hereinafter as the "Federal floor proviso."[13]

[13] In the context of the Federal floor proviso, an "approved" contract is one that the lessor accepts as reflecting the reasonable market value of the gas. "Approved" in this context does not mean that the lessor approved the lessee's entering into the contract in the first instance.

5. The Federal floor proviso requires EOG to pay royalty on gas produced from or allocated to the subject state leases on the basis of a value of production that is not less than the value of the gas production determined under Federal royalty valuation regulations.

B. Requirements under Federal Royalty Valuation Rules, Including the Marketable Condition Rule[14]

6. Under the Federal royalty valuation rules in effect since 1988, for gas or residue gas and gas plant products sold under an arm's-length contract, with certain exceptions not relevant here, the lessee's gross proceeds are accepted as the royalty value (before deductions for applicable processing and transportation allowances discussed below). The lessee's gross proceeds are the total monies and other consideration accruing to the lessee for the disposition of the gas, residue gas, and gas plant products produced. The lessee's gross proceeds are also the minimum value for royalty purposes.

7. Under the Federal royalty valuation rules, where the value of gas has been determined at a point—*e.g.*, a sales point—off the lease or unit, the lessee may deduct the reasonable actual costs of transporting residue gas and gas plant products from a lease or unit to a point off the lease or unit, including, when appropriate, transportation from the lease or unit to a gas processing plant off the lease or unit and from the plant to a point away from the plant. This deduction commonly is referred to as a "transportation allowance."

8. Under the Federal royalty valuation rules, unless the Department of the Interior's Office of Natural Resources Revenue (ONRR) grants specific approval, a transportation allowance for gas or gas plant products produced from Federal leases may not exceed 50 percent of the value of the residue gas or gas plant product.

9. The Federal royalty valuation rules provide for deductions for the cost of processing gas for the extraction of valuable products such as NGLs. This deduction commonly is referred to as a "processing allowance." Processing costs may not be applied against the value of the residue gas, unless ONRR approves an extraordinary processing cost exception. Ordinarily, the processing allowance may not exceed 66⅔ percent of the value of the extracted NGLs, with value first reduced for any transportation allowances related to post-processing transportation.

10. Under current and predecessor Federal royalty valuation regulations in effect for almost 80 years, lessees must treat production to put it in marketable condition at no cost to the lessor, *i.e.*, without deducting the costs of treatment or conditioning functions in computing royalty value.

11. Functions necessary to put gas into marketable condition include, depending on the particular circumstances, gathering, compression, dehydration, and sweetening/desulphurization. Further, Federal royalty valuation rules do not permit an allowance for the costs of compressing

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[14] The Federal royalty valuation regulations referred to in these Conclusions of Law are cited and quoted extensively in the Legal Analysis below. Citations to specific sections of the rules are omitted here to avoid burdensome duplication.

residue gas after processing. Part IV of these conclusions of law below addresses these requirements in more detail, including how they apply to the facts of this case.

12. Under Federal royalty valuation rules, gas is in marketable condition when it is sufficiently free from impurities and otherwise in a condition that it will be accepted by a purchaser under a sales contract typical for the field or area.

II. The Implied Covenant to Market

13. Under the subject state leases, there is an implied covenant on the part of the lessee to market production for the mutual benefit of the lessee and the lessor.

14. In the opinion of the Board, the implied covenant to market obligates the lessee to perform at its own expense those functions which, under the circumstances, are necessary to put production into marketable condition, and the value at the well provision does not allocate to the respective parties to the lease costs incurred after physical severance occurs. In any event, the Federal floor proviso controls.

III. Gas Used as Fuel

15. Residue gas produced from, or allocated to, the subject state leases that is used as fuel in compressors or other facilities along the Questar pipeline downstream of the inlet to that line is a part of the transportation cost EOG incurs. These volumes are royalty-bearing and therefore must be included in the total volume on which royalty is owed and calculated. At the same time, the value of the volumes used as fuel is a cost of transportation and may be deducted in calculating the value of the total royalty-bearing volume. The deducted amount counts toward the 50 percent cap on allowable transportation costs. The sum of transportation costs paid in cash and the value of volumes used as fuel along the pipeline may not exceed 50 percent of the value of the total of the royalty-bearing volumes (*i.e.*, the delivered volumes plus the fuel-use volumes).

16. Gas produced from or allocated to the subject state leases that is consumed as fuel, in operations conducted on the lease or unit from which the gas is produced, is not royalty-bearing, even if the gas is used in operations the cost of which otherwise would not be deductible (*e.g.*, functions necessary to put the gas into marketable condition).

17. Neither the terms of the state leases involved in this appeal nor applicable state statutes or regulations provide for royalty-free use of gas as fuel in operating a processing plant located *off* the lease or unit from which the gas is produced. The Federal floor proviso does not make 30 C.F.R. § 1202.151(b) (2011-2020) (formerly 30 C.F.R. § 202.151(b) (1988-2010)) (allowing royalty-free use of a reasonable amount of residue gas for operation of the processing plant, including plants located off the lease or unit) applicable to the state leases involved here. Gas used as fuel in operation of a processing plant located *on* the lease or unit from which the gas is produced is royalty-free.

IV. Marketable Condition Requirements

18. Gas produced from or allocated to the subject state leases is in marketable condition when it has been gathered—*i.e.*, accumulated to a central accumulation or treatment point—and meets the pressure specifications and quality requirements, including maximum water content and acid gas levels, for acceptance into the Questar pipeline.

A. Gathering and Relationship to Transportation Allowances

19. With respect to gathering, all movement of gas produced from or allocated to ML 3077, ML 3078, and ML 3355 in the Chapita Wells Unit that was processed at the Iron Horse, Stagecoach, or Chipeta plants before the inlet to the Questar pipeline, as well as all treatment and processing of that production, occurred on the unit. Therefore, EOG may not claim a transportation allowance for any movement of that gas before the inlet to the Questar pipeline.

20. For gas produced from, or allocated to, ML 3077, ML 3078, and ML 3355 in the Chapita Wells Unit that was processed at the Red Wash plant, movement of that production from the Coyote compressor station to the Red Wash plant, and movement of residue gas downstream of the Red Wash plant, constitutes transportation, the costs of which are deductible as a transportation allowance in determining royalty value, subject to the 50 percent limitation discussed in paragraph 15 above.

21. Movement of gas allocated to ML 1299 in the Stagecoach Unit upstream of the Coyote compressor station is gathering, the costs of which are not deductible. Movement of that gas through the line beyond the Coyote compressor station to any of the processing plants and further downstream from the plants constitutes transportation, the costs of which are deductible as a transportation allowance, subject to the 50 percent limitation discussed in paragraph 15 above.

22. Before completion of the ECW Section 16 Central Facility in 2013, movement of gas produced from wells on ML 47045 upstream of the Coyote compressor station during this period is gathering, the costs of which are not deductible. Movement of this gas beyond the Coyote compressor station to any of the processing plants and further downstream from the plants constitutes transportation, the costs of which are deductible as a transportation allowance, subject to the 50 percent limitation discussed in paragraph 15 above.

23. After the ECW Section 16 Central Facility began operation in 2013, movement of production from wells on ML 47045 to that facility constitutes gathering, the costs of which are not deductible. After the ECW Section 16 Central Facility began operation, movement of the gas from that facility through the line to the Chapita and Coyote compressor stations and any of the processing plants and points further downstream constitutes transportation, the costs of which are deductible as a transportation allowance, subject to the 50 percent limitation discussed in paragraph 15 above.

24. Movement of gas produced from the single well on ML 45681 to the off-lease FMP is not deductible as a transportation cost. Movement of the gas through the line downstream of

the FMP constitutes transportation, the costs of which are deductible as a transportation allowance, subject to the 50 percent limitation discussed in paragraph 15 above.

25. No gathering functions are involved for production from ML 48380, and all movement of this gas after the FMP constitutes transportation, the costs of which are deductible as a transportation allowance, subject to the 50 percent limitation discussed in paragraph 15 above.

B. Compression and Relationship to Transportation Allowances

26. For all the gas produced from or allocated to ML 3077, ML 3078, and ML 3355 in the Chapita Wells Unit and ML 1299 in the Stagecoach Unit, or produced from non-unitized ML 47045 and ML 45681, compression at the Chapita and Coyote compressor stations (or at the Coyote compressor station for gas that did not go through the Chapita compressor) was necessary to attain the pressure necessary for the gas to be in marketable condition. The costs of compression at the Chapita compressor station are not deductible in determining royalty value. With the exception noted in the next paragraph, the costs of compression at the Coyote compressor station are not deductible in determining royalty value.

27. For gas discharged from compressor units at the Coyote compressor station at approximately 1,100 psig, that pressure is higher than the pressure necessary for the gas to be in marketable condition. Under ONRR's allowed methodology for allocating between treatment and transportation functions costs paid as so-called "bundled" fees under contracts for gathering and compression services, the portion of the costs of compression at those units which corresponds to the difference between the compressor unit discharge pressure (1,100 psig) and the pressure necessary to enter the Questar pipeline (950 psig) may be deductible in calculating royalty value under the Federal floor proviso. This is addressed further below.

28. The costs of compression of residue gas after processing at any of the processing plants or at the Fidlar compressor station are not deductible in determining royalty value.

29. The portion of gas, or, in the case of the Fidlar compressor station, residue gas, produced from or allocated to ML 3077, ML 3078, and ML 3355 in the Chapita Wells Unit that was used as fuel in the Chapita, Coyote, and Fidlar compressor stations is not royalty-bearing.

30. The portion of gas or residue gas used as fuel in any of the compressors that is allocable to ML 1299 in the Stagecoach Unit or to ML 47045 and ML 45681 is royalty-bearing. These volumes must be added to the reported volumes for these leases if EOG did not include them in its original royalty reports.

C. Dehydration

31. The costs of dehydrating any of the gas produced from or allocated to any of the subject leases are not deductible in determining royalty value.

32. Gas used as fuel in dehydration equipment located at the wells or on the lease or unit from which the gas was produced, such as the ECW Section 16 central facility on Lease 47045 or the Davies Road central facility on the Chapita Wells Unit, is not royalty-bearing.

33. Gas used as fuel in dehydration equipment at the wellhead location for ML 45681 is not royalty-bearing.

D. Desulphurization

34. To the extent that gas produced from, or allocated to, ML 1299, ML 3077, ML 3078, ML 3355, ML 47045 and ML 45681 was desulphurized, the costs of desulphurization are not deductible in calculating royalty value.

35. Gas used as fuel in desulphurization equipment located at the wells or on the lease or unit from which the gas was produced is not royalty-bearing.

V. Unbundling Cost Analyses Used as "Proxies" and Use of ONRR-Suggested Methods

36. The 2012 Audit Report's use of ONRR's unbundling cost analysis for the Manzanares gas system in New Mexico as a "proxy" to separate deductible from non-deductible costs in combined fees paid for the QEP Resources gathering system involved in this appeal is without legal basis.

37. ONRR's unbundling cost analysis for the Chipeta processing plant would apply to gas produced from or allocated to the state leases involved in this appeal that is processed through that plant to separate deductible from non-deductible costs in combined fees paid for processing gas at that plant. It would be unlawful to use the Chipeta plant unbundling cost analysis as a "proxy" for the Stagecoach, Iron Horse, or Red Wash plants.

38. In the absence of an ONRR-calculated unbundling cost analysis for the QEP Resources gathering system involved in this appeal, using ONRR's published suggested method for "unbundling" deductible and non-deductible costs in combined fees paid for transportation systems would be proper as a matter of law.[15]

39. In the absence of ONRR-calculated unbundling cost analyses for the Stagecoach, Iron Horse, or Red Wash plants, using ONRR's published suggested method for "unbundling" deductible and non-deductible costs in combined fees paid for processing at those respective plants would be proper as a matter of law.[16]

[15] *See* "How to Calculate a Transportation UCA" at https://www.onrr.gov/unbundling/pdf/How-to-calculate-a-Transportation-UCA.pdf.

[16] *See* "How to Calculate a Processing UCA" at https://www.onrr.gov/unbundling/pdf/How-to-calculate-a-Processing-UCA.pdf.

40. Further argument and analysis concerning the development and use of UCAs is appropriate in the 'recalculation' phase of this matter as this issue has not been the subject of significant briefing.

VI. Processing Costs and Processing Allowance Cap

~~40~~41. Under both the express terms of the subject state leases and Federal rules applicable under the Federal floor proviso, processing costs may be deducted in computing the royalty value only of royalty-bearing extracted products such as NGLs. Processing costs may not be deducted in computing the royalty value of residue gas.

~~41~~42. Under both the lease terms and the applicable Federal rules, the processing cost deduction is applied after transportation costs have been deducted from a sales price for the extracted products, such as NGLs, received at a remote downstream point of sale, or from a downstream measure of value that is the basis for calculation of royalty value.

~~42~~43. ONRR has no authority to approve a processing cost allowance in excess of the limit of 66⅔ percent of the value of the extracted NGLs for NGLs derived from processing gas produced from or allocated to a state lease. However, if ONRR has approved a processing cost allowance for EOG in excess of the two-thirds limit for gas produced from Federal leases which is processed in the same plants, that must be taken into account in calculating the minimum royalty value of gas produced from or allocated to the state leases under the Federal floor proviso. Moreover, under the express terms of the royalty clause of the subject leases, SITLA has authority to approve processing allowances that exceed the cap.

~~43~~44. Gas used as fuel in the Red Wash plant is royalty-bearing. The value of the gas used as fuel in that plant is part of the cost of processing, and counts toward the 66⅔-percent processing allowance cap.

~~44~~45. Gas produced from or allocated to ML 3077, ML 3078, and ML 3055 in the Chapita Wells Unit that is used as fuel in the Stagecoach, Iron Horse, or Chipeta plants is royalty-free. Gas that is allocated to ML 1299 in the Stagecoach Unit, or produced from ML 47045 or ML 45681, that is used as fuel in the Stagecoach, Iron Horse, or Chipeta plants is royalty-bearing. The value of that fuel gas is part of the cost of processing and counts toward the 66⅔-percent processing allowance cap.

VII. Transportation Allowance and Transportation Allowance Cap

~~45~~46. ONRR does not have authority to approve transportation cost deductions (allowances) in excess of the Federal regulatory cap of 50 percent of the value of the residue gas or gas plant product transported (applicable by virtue of the Federal floor proviso) for gas produced from or allocated to state leases.

~~46~~47. The Federal floor proviso in the leases does not give SITLA power to exercise authority granted to the Secretary of the Interior and his delegates under the Federal mineral leasing laws and Federal rules to approve an application for a transportation allowance in excess of the 50 percent limit.

~~47~~48. If EOG has applied for and received from ONRR approval of a transportation allowance in excess of the 50 percent limit for gas produced from or allocated to EOG's Federal leases that is transported to the same points of sale under the same transportation contract and transportation arrangements as gas produced from or allocated to EOG's state leases, SITLA must take the excess transportation allowance into account in determining the minimum royalty value of that gas under the Federal floor proviso.

~~48~~49. The portion of the costs of transporting gas produced from or allocable to ML 3077, ML 3078, and ML 3355 in the Chapita Wells Unit and ML 1299 in the Stagecoach Unit, or produced from any of the non-unitized state leases, to the Red Wash plant that is properly allocable to NGLs extracted by processing and sold at that plant may be deducted as a transportation allowance in calculating the royalty value of the NGLs. That deduction may not exceed 50 percent of the value of the NGLs.

~~49~~50. The portion of the costs of transporting gas (1) allocable to ML 1299 in the Stagecoach Unit or (2) produced from ML 47045 or ML 45681 to the Stagecoach, Iron Horse, or Chipeta plants that is properly allocable to NGLs extracted by processing and sold at those plants may be deducted as a transportation allowance in calculating the royalty value of the NGLs. That deduction also may not exceed 50 percent of the value of the NGLs.

~~50~~51. No transportation allowance may be taken in calculating the royalty value of NGLs extracted at the Stagecoach, Iron Horse, or Chipeta plants from gas produced from, or allocable to, ML 3077, ML 3078, and ML 3355 in the Chapita Wells Unit.

VIII. Statutes of Limitations

~~51~~52. The respective statutes of limitations at Utah Code Ann. §§ 78B-2-201 and 78B-2-309 apply to judicial lawsuits. Neither of these statutes operates to bar administrative orders such as the SITLA Audit Reports involved in this appeal.

~~52~~53. Utah Code Ann. § 78B-2-201(1)(b), which bars actions with respect to the issues or profits of any real property, based upon the State's right or title to the real property, unless the state received all or a portion of the rents and profits from the real property within the immediately preceding seven years, would apply to a lawsuit by the State to enforce a final administrative order to pay royalties due.

~~53~~54. The six-year statute of limitations in Utah Code Ann. § 78B-2-309(1)(b) for actions "upon any contract, obligation, or liability founded upon an instrument in writing" would not apply to a lawsuit by the State to enforce a final administrative order to pay royalties due.

~~54~~55. An action by the State to enforce a final administrative decision in the instant case requiring EOG to pay additional royalty would be timely under Utah Code Ann. § 78B-2-201(1)(b) as a matter of law if the leases are producing when the State brings the action.

IX. Equitable Right to Recoup Overpayments, Offsets of Overpayments and Underpayments During the Audit Period, and Right to Refund of Overpayments

~~55~~56. The royalty due on gas produced during a particular month is not a separate and distinct legal obligation that stands completely independent of, and is unrelated to, royalty due on gas produced in every other month. While royalty must be paid monthly, the question posed in an audit is whether royalty on all production from the lease during the period under review is underpaid, correct, or overpaid.

~~56~~57. SITLA has no legal right to demand payments plus interest for underpaid months and refuse to offset or credit overpayments in overpaid months. SITLA has no legal right to insist that the lease be maintained in an overpaid status.

~~57~~58. The "voluntary payment doctrine" does not bar EOG from recouping, or seeking a refund of, royalty overpayments made in prior months. Although the subject lease instruments are silent on the subject, EOG as lessee has an inherent right to recoup overpayments.

~~58~~59. The lessee's equitable right to recoup overpayments is not contingent or dependent upon a lessee also being able to recover overpayments through judicial litigation. The lessee's right to recoup overpayments on its own initiative may still apply even if a judicial lawsuit to recover overpayments would or may be barred—for example, if a lawsuit would be time-barred under an applicable statute of limitations.

~~59~~60. If an audit, in correctly applying the law to the facts, finds that there are overpayments of royalty for a lease in some months and underpayments of royalty in other months, the overpayments must be credited against amounts due for underpaid months to determine whether royalty on production from the lease has been underpaid during the audit period.

~~60~~61. If a lease is net underpaid after all overpayments and underpayments during the audit period have been offset, interest at the rate prescribed under applicable law or regulation should be assessed on the amount by which the lease was underpaid, beginning when the lease became net underpaid and remained net underpaid through the end of the ~~July~~ January 2007 through December 2017 audit period, until the amounts owing are paid.

~~61~~62. Although the subject lease instruments themselves do not include an express right to a refund of overpayments, a lessee has a right of action to recover excess royalty payments as an action for "monies had and received," which is a claim under a contract implied in law and is another term for a claim for unjust enrichment.

~~62~~63. A claim by EOG for a refund of allegedly overpaid royalties would not be barred because of alleged failure to exhaust available legal remedies.

~~63~~64. Failure to state a claim upon which relief can be granted is an affirmative defense to a claim for relief in a civil lawsuit and a ground for dismissal of lawsuit under Rule

12(b)(6) of the Utah Rules of Civil Procedure. The affirmative defense of failure to state a claim has no application in the context of an administrative appeal.

~~64~~65. The Governmental Immunity Act of Utah, Utah Code Ann. §§ 63G-7-101 *et seq*., does not prevent EOG from recovering past overpayments, either through recoupment or judicial litigation.

LEGAL ANALYSIS

Introduction

The lease instruments require the lessee to conduct all operations in accordance with current and future regulations.[17] Under the lease terms, SITLA as lessor has the right to cancel the lease administratively for noncompliance with any of the lease terms, after notice and a 30-day period to correct the noncompliance.[18] SITLA as lessor has the authority to require the lessee to produce documents and records relative to royalty payments and other matters.[19]

Utah Code Ann. § 53C-2-411 authorizes state leases to be committed to unit or other cooperative agreements. Subsection (3) of that section provides that "[p]roduction allocated to leased trust lands under the terms of a unit, cooperative, or other plan of development shall be considered produced from the leased lands whether or not the point of production is located on the leased trust lands." *See also* Utah Admin. Code R850-21-500(3). Section 5(c) of each of the lease instruments likewise grants SITLA as lessor "[t]he right, with the consent of the LESSEE, to commit the hereby leased lands to a unit or co-operative plan of development, and to establish, alter or change the drilling, producing and royalty requirements and terms of this lease to conform thereunto."

Because the Chapita Wells Unit and the Stagecoach Unit include (and consist predominantly of) Federal oil and gas leases, as noted above, Federal unitization regulations at 43 C.F.R. Part 3180 apply and the unit agreements are Federally-prescribed forms.[20] Section 12 of both unit agreements provides in relevant part:

> 12. ALLOCATION OF PRODUCTION. All unitized substances produced from each participating area established under this agreement . . . shall be deemed to be produced equally on an

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[17] Section 6(b)(7) of ML 1299, ML 45681, ML 47045, and ML 48380; section 6(c)(7) of ML 3077, ML 3078, and ML 3355.

[18] *See* section 10 of each of the subject leases.

[19] Section 14 of ML 1299, ML 45681, ML 47045, and ML 48380; section 11 of ML 3077, ML 3078, and ML 3355.

[20] The Chapita Wells Unit Agreement is found at APP 000072; the Stagecoach Unit Agreement is found at APP 000095.

> acreage basis from the several tracts of unitized land of the participating area established for such production and, for the purpose of determining any benefits accruing under this agreement, each such tract of unitized land shall have allocated to it such percentage of said production as the number of acres of such tract included in said participating area bears to the total acres of unitized land in said participating area . . . . It is hereby agreed that production of unitized substances from a participating area shall be allocated as provided herein regardless of whether any wells are drilled on any particular part or tract of said participating area. . . .

Thus, EOG owes royalty to SITLA on the portion of the volumes produced from the respective participating areas that is allocated to each of the unitized state leases.

I. The Meaning and Application of the Federal Floor Proviso

A. The Federal Floor Proviso Requires Royalty Payment on at Least the Value of Production as Determined under Federal Royalty Valuation Rules.

The gas royalty clause in section 4(b) of each of the subject leases provides:

> LESSEE agrees to pay to LESSOR twelve and one-half (12½) percent of the reasonable market value at the well of all gas produced and saved or sold from the leased premises. Where gas is sold under a contract, and such contract has been approved in whole or conditionally by the LESSOR, the reasonable market value of such gas for the purpose of determining the royalties payable hereunder, shall be the price at which the production is sold, provided that in no event shall the price for gas be less than that received by the United States of America for its royalties from gas of like grade and quality from the same field. Provided expressly that the reasonable market value of processed or manufactured or extracted products, for the purpose of computing royalties hereunder, shall be the value after deducting the costs of processing, extracting or manufacture, except that the deduction for such costs may not exceed two-thirds of the amount of the gross of any such products without approval by the LESSOR and, provided further that the market value of extracted, processed or manufactured products used in the computation of royalties hereunder shall not be less than the value used by the United States in its computation of royalties on similar products resulting from production of like grade and quality in the same field. [Emphasis added.][21]

[21] In the three newest lease instruments involved in this proceeding (ML 45681, ML 47054, and

The first two sentences apply to unprocessed gas sold or disposed of as such, and to residue gas sold or disposed of after processing. The last sentence, beginning with “Provided expressly” and including the underscored language near the end, applies to NGLs extracted from the gas stream by processing. The underscored provisos often are referred to as the “Federal floor” provisos for the respective categories of production to which each applies.

The oil royalty clause in section 4(a) of each of the subject leases also contains a Federal floor proviso. It provides in relevant part that “in no event shall the royalties be based upon a market value less than that used by the United States in the computation of royalties, if any, paid by this LESSEE to the United States of America on oil of like grade and gravity produced in the same field.” (Emphasis added.)

The most important issue disputed between the parties is the meaning of the Federal floor proviso for gas and its relationship to the value at the well provision. Both parties agree, and so reaffirmed at oral argument, that the Federal floor proviso applies and, as a specific proviso, controls. However, they disagree as to what the Federal floor proviso requires.

EOG argues that the value at the well provision entitles EOG to deduct all costs of gathering, transportation, processing, compression and marketing after gas surfaces at the wellhead. EOG Opening Brief, pp. 5-9; Response Brief of Petitioner EOG Resources, Inc. (“EOG Response Brief”), pp. 3-13. EOG characterizes its interpretation of the value at the well provision as the majority view of courts in other states, as opposed to what it characterizes as the minority view of courts in other states, which have adopted a “first marketable product” or “marketable condition” rule, as discussed further below. EOG Opening Brief, pp. 5-6. EOG argues that the Utah Supreme Court would adopt the apparent majority view.[22]

As articulated at oral argument, EOG maintains that the Federal floor proviso requires that the price used as the basis for calculating royalty must at least equal the price at which lessees of Federal leases in the field sell production from those leases. Once that requirement is

ML 48380, originally entered into between 1992 and 2000), the phrase “except that the deduction for such costs [*i.e.,* of processing, extracting, or manufacture] may not exceed two-thirds of the amount of the gross of any such products” without approval of the lessor is replaced by the phrase “except that the deduction deducting the costs of processing, extracting, or manufacturing may not exceed two-thirds of the amount of the gross of any such products” without approval of the lessor. The difference in phraseology is immaterial. The underscored language is identical in all the lease instruments.

[22] States that have taken the view that a “value at the well” (or “market price at the well”) royalty clause allows a lessee to deduct costs of treating production to put it in marketable condition include California, Texas, Louisiana, North Dakota, and Kentucky. *See, e.g., Atlantic Richfield Co. v. State of California*, 214 Cal. App. 3d 533 (Cal. App. 1989); *Heritage Resources v. Nationsbank*, 939 S.W.2d 118 (Tex. 1996); *Babin v. First Energy Corp.*, 693 So. 2d 813 (La. Ct. App. 1997) (royalty clause not quoted); *Bice v. PetroBHunt, L.L.C.*, 2009 ND 124, 768 N.W.2d 496 (2009); and *Baker v. Mangum Hunter Production, Inc.*, 473 S.W.3d 588 (Ky. 2015).

met, then the value at the well provision entitles lessees of state leases to deduct from that price all costs incurred after gas is produced at the well.

SITLA argues that the Federal floor proviso requires EOG to pay royalty on a minimum of the value of the production determined under Federal royalty valuation rules. Opening Brief of Utah School and Institutional Trust Lands Administration Concerning Threshold Legal Issues ("SITLA Opening Brief"), pp. 2, 7-16; Reply Brief of Utah School and Institutional Trust Lands Administration Concerning Threshold Legal Issues ("SITLA Reply Brief"), pp. 3-6.

1. The Utah Supreme Court Held in 1994 that under the Federal Floor Proviso, Royalty Value under a State Lease Cannot Be Less than the Royalty Value of Gas of Like Grade and Quality Produced from Federal Leases in the Same Field.

The only Utah case addressing the Federal floor proviso in the subject leases is *Enron Oil and Gas v. State, DNR*, 871 P.2d 508 (Utah 1994). That case involved EOG's corporate predecessor, Enron Oil and Gas Corp., and production during an earlier time period from the same three leases in the Chapita Wells Unit which are involved in this appeal.[23] The question was whether Enron owed royalty to the State on reimbursements it received from its purchaser for severance taxes Enron paid to the State on the gas produced from its leases. SITLA relies on the majority opinion in *Enron*; EOG relies on Justice Durham's dissent in that case. Some brief background explanation is necessary to analyze the parties' respective arguments.

Sections 102 through 109 of the Natural Gas Policy Act ("NGPA"), former 15 U.S.C. §§ 3312-3319 (repealed effective January 1, 1993), which were in effect at the time of the sale of production involved in the *Enron* case, established the "maximum lawful price" at which various categories of gas could be sold. Section 110(a) of the NGPA, former 15 U.S.C. § 3320(a) (repealed effective January 1, 1993), then provided in relevant part that

> a price for the first sale of natural gas shall not be considered to exceed the maximum lawful price applicable to the first sale of such natural gas under this subtitle if such first sale price exceeds the maximum lawful price to the extent necessary to recoverC
>
> (1) State severance taxes attributable to the production of such natural gas and borne by the seller . . . .

Thus, in addition to the per-unit contract sale price, a lessee-seller was permitted to receive reimbursements for state severance taxes that it paid as part of the allowed "first sale price" under the NGPA.

[23] That case also involved production from the Natural Buttes Unit, which adjoins the Stagecoach Unit and the Chapita Wells Unit on the west and south and is another unit in the Natural Buttes Field. However, production from the Natural Buttes Unit is not involved in this appeal.

The terms of Federal oil and gas leases, as well as the statute authorizing oil and gas leases on Federal public domain lands, the Mineral Leasing Act ("MLA") at 30 U.S.C. § 226(b), provide for royalty as a percentage of the value of the production removed or sold from the lease. The lease terms reserve to the Secretary of the Interior the authority to establish the reasonable value of production for royalty purposes, and the MLA grants rulemaking authority to the Secretary. 30 U.S.C. § 189. Under Federal royalty valuation rules in effect for almost 80 years and applicable judicial precedents, the value of production for royalty purposes cannot be less than the "gross proceeds" accruing to the lessee for the sale or disposition of the production, *i.e.*, the total consideration the lessee receives for disposition of the production.[24] *E.g.*, *Enron Oil & Gas Co. v. Lujan*, 978 F.2d 212, 216 (5th Cir. 1992); *Hoover & Bracken Energies, Inc. v. United States Dep't. of the Interior*, 723 F.2d 1488, 1492 (10th Cir. 1983); *Amoco Production Co.*, 29 IBLA 234, 238 (1977); *Wheless Drilling Co.*, 13 IBLA 21, 32 (1973).

In the Utah Supreme Court's 1994 *Enron* decision, the majority held:

> This provision [the Federal floor proviso] places a floor on the price of gas for royalty calculations and ensures that the leases are "in the best interest of the state," as required by Utah Code Ann. § 65-1-18 and the terms of the state school land trust. The price of gas for determining federal royalties has consistently been held to include tax reimbursements. *E.g.*, *Enron Oil & Gas Co. v. Lujan*, 978 F.2d 212, 216 (5th Cir. 1992); *Hoover & Bracken Energies, Inc. v. United States Dep't of Interior*, 723 F.2d 1488, 1492 (10th Cir. 1983); *Amoco Prod. Co.*, 29 I.B.L.A. 234, 238 (1977); *Wheless Drilling Co.*, 13 I.B.L.A. 21, 32 (1973). "If the market value or amount realized is higher than the federal floor, royalties must be paid on the basis of market value or amount realized. Conversely, if the . . . market value is lower than the federal floor, royalties must be paid on the basis of the federal floor." *State v. Moncrief*, 720 P.2d 470, 474 (Wyo.1986). If Enron were to sell gas based at a price less than the floor provision when the reasonable market value would yield a higher price, the Division could reject such a contract. See *Moncrief*, 720 P.2d at 474-75.

871 P.2d at 511. The majority states that the "price of gas for determining Federal royalties has consistently been held to include tax reimbursements," citing for that proposition the Fifth Circuit, Tenth Circuit, and IBLA decisions cited above. All of these decisions held that because severance tax reimbursements were part of the total consideration paid to the lessee for disposition of the gas, they were part of the lessee's "gross proceeds" and therefore part of the minimum value of the gas on which the lessee owes royalty. The United States did not receive

[24] Former 30 C.F.R. § 221.47 (1942-1982) (7 Fed. Reg. 4132, 4137 (June 2, 1942)), redesignated as former 30 C.F.R. § 206.103 (1983-1987) (48 Fed. Reg. 35641 (Aug. 5, 1983)); former 30 C.F.R. §§ 206.152(h) and 206.153(h) (1988-2010), 53 Fed. Reg. 1230, 1275, 1277 (Jan. 15, 1988), redesignated as 30 C.F.R. §§ 1206.152(h) and 1206.153(h) (2011-2020) (75 Fed. Reg. 61051, 61069 (Oct. 4, 2010)).

tax reimbursements as part of the price received for selling gas. The United States as lessor and royalty owner did not sell the gas; the lessee sold the gas, and its purchaser reimbursed the lessee for severance taxes assessed on the production sold that the lessee paid to the State. Thus, in saying that "[t]he price of gas for determining federal royalties has consistently been held to include tax reimbursements," the majority necessarily is speaking of the value of gas on which royalty is calculated, and how the Federal royalty valuation rules applied to tax reimbursements.

The majority's language in substance interprets the Federal floor proviso as meaning that the value on which royalty is owed to the State under a state lease cannot be less than the value on which royalties are owed to the United States on gas of like grade and quality produced from Federal leases in the same field.

The majority cited the decision in *State of Wyoming v. Moncrief*, 720 P.2d 470 (Wyo. 1986), for the principle that royalty is owed on the higher of (1) the market value of the gas or the amount realized from the sale of gas, or (2) the Federal floor. The Federal floor proviso in the leases involved in *Moncrief* was essentially identical to the Federal floor proviso for unprocessed gas and residue gas in the leases involved in this appeal.[25]

In *Moncrief*, all eight lessees in the Long Butte Unit sold their production under contracts that each of them had entered into with various purchasers. The State Auditor had issued orders to all eight lessees to pay royalty on the highest price paid for any gas produced from the field. The Wyoming Supreme Court held that the lease instrument did not support a demand for royalty on that basis, and that the lessees were required to pay royalty on the basis of the higher of the amount the lessee received from sale at the wells (or the market value at the wells if not sold at the wells) or the Federal floor. 720 P.2d at 474.

The *Moncrief* decision did not address the question of what the Federal floor proviso means or how it would apply in various circumstances. However, the Wyoming Supreme Court did address its meaning in a subsequent case, *Cities Service Oil and Gas Corp. v. State*, 838 P.2d 146 (Wyo. 1992). Like the *Enron* case in Utah, *Cities Service* presented the question of whether royalty was owed on severance tax reimbursements allowed under section 110(a) of the NGPA. The gas royalty clause in the leases in the *Cities Service* case was identical to the royalty clause in the leases involved in *Moncrief*. As noted previously, the Federal floor proviso in that clause is functionally identical to the Federal floor proviso in the subject lease instruments. In holding that the Federal floor proviso required the lessee to pay royalty on severance tax reimbursements, the Wyoming Supreme Court explained:

> Under the "federal floor" provision in the state leases, the State is entitled to receive the same royalty revenue that the federal government gets from its leases in the same field. If other gas

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[25] The Wyoming state leases involved in *Moncrief* provided for a royalty on gas "produced from said land saved and sold or used off the premises or in the manufacture of gasoline or other products therefrom, the market value at the well of one-eighth of the gas so sold or used," and included a proviso that "in no event shall the price for gas, or natural gasoline, be less than that received by the United States of America for its royalties from the same field." 720 P.2d at 472-473 (emphasis added).

> producers in the same field remit royalties to the federal government calculated on the basis of NGPA ceiling price plus tax reimbursements, then state lease gas producers must calculate their State royalty payments on the same basis. This is a common sense conception that what is the same is also equal or what is not equal cannot be the same. We disagree with Oxy's argument that to construe the "federal floor" provision as establishing "federal royalty receipts" as a minimum for the royalties due under the state leases requires the royalty clause of the leases to be rewritten to conform to the federal government's view of what the "value of production" should be for federal royalty payment purposes. The underlying purpose behind the "federal floor" provision incorporated in the royalty clause in the state leases clearly mandates that the State shall receive nothing less than what the federal government gets in the way of royalty payments from natural gas wells on federal land in the same field.
>
> Oxy's narrow interpretation of the "federal floor" provision fails to take into account the significance of the federal government=s "royalties from the same field" language. This phrase, when read in conjunction with the rest of the royalty provision, implies that the State's royalty will not be less than the federal government's royalty C not just the "price" used to calculate the federal government's royalty.

838 P.2d at 153 (emphasis added). The Utah Supreme Court's ruling in *Enron* is consistent with the Wyoming Supreme Court's reading of the underlying purpose of the Federal floor proviso as mandating that "the State shall receive nothing less than what the federal government gets in the way of royalty payments from natural gas wells on federal land in the same field." Further, "what the federal government gets in the way of royalty payments" is determined by applying the Federal royalty valuation rules to the production disposed of by the Federal lessees.

The lessee of a state lease has no legal authority to compel lessees of Federal leases in the same field to disclose the sales prices or the royalty value of production from or allocated to Federal leases in the field, or the royalties paid on that production. If the point of the Federal floor proviso is that the State is to receive no less royalty on production from or allocated to the state leases than the Federal government receives on production of like grade and quality from Federal leases in the same field, the only way to do so is to determine the value of the state lease production under the Federal royalty valuation rules. That is what both the Utah Supreme Court and the Wyoming Supreme Court did in *Enron* and *Cities Service*, respectively.[26]

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[26] EOG suggested at oral argument that the *Cities Service* decision was a consequence of the Wyoming Royalty Payment Act of 1982, Wyo. Stat. §§ 30-5-301 - 30-5-305. In that Act, Wyoming required lessees to bear the costs necessary to put production into marketable condition. (*See* the definitions of "lessee," "lessor," "royalty," and "costs of production" in section 30-5-304.) EOG's argument is flawed. First, the Wyoming Supreme Court never

2. Justice Durham's Dissent in *Enron* and EOG's Current Position

EOG relies on Justice Durham's dissent in *Enron*, 871 P.2d at 515. In her dissent, Justice Durham first asserted that severance tax reimbursements were not paid as part of the consideration for the gas purchased, but rather "in return for its commitment to a long-term contract, not as consideration for the gas itself." 871 P.2d at 513-514. Her assertion does not accurately reflect the regulatory scheme of the NGPA or the Fifth Circuit's holding *Enron Oil & Gas Co. v. Lujan* and the Tenth Circuit's holding in *Hoover & Bracken*. Severance taxes are imposed and assessed on volumes produced and sold. Justice Durham overlooked section 110(a) of the NGPA, quoted above, that specifically allowed the first sale price to include tax reimbursements in addition to the maximum lawful per-unit stated price. Severance tax reimbursements therefore necessarily are part of the price the purchaser pays for the production. In *Enron Oil & Gas Co. v. Lujan* and *Hoover & Bracken*, the Fifth Circuit and the Tenth Circuit, respectively, both held that tax reimbursements were part of the total consideration paid for the production, not as value given for a contract independent of the production sold under that contract.

The Utah Supreme Court majority recognized this in expressly rejecting Justice Durham's argument. The majority observed that "the distinction the dissent draws is not in accord with economic realities. Severance taxes are a seller's cost of production, and when such a cost is paid for by a buyer, the value of the gas is increased accordingly." 871 P.2d at 511.

If, in Justice Durham's view, tax reimbursements are not part of the consideration paid for specific volumes of gas sold, they could not be part of the price of gas, and therefore would not be part of the "price for gas . . . received by the United States of America for its royalties" under the Federal floor proviso. Thus, misstating the relationship of tax reimbursements to the price of production sold appears to have led Justice Durham to her conclusion that the lessee of a state lease would not owe royalty on those reimbursements under that proviso.

Justice Durham went on to observe that all the gas produced from both the state and Federal leases in the Chapita Wells Unit and the Natural Buttes Unit that was involved in that case was sold under the same agreements. She then maintained:

> Enron's lease agreement with the state merely stipulates that the price received for production under approved natural gas purchase

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mentioned the Wyoming Royalty Payment Act in the *Cities Service* decision. Second, *Cities Service* involved tax reimbursements, not costs of treating production to make it marketable. The Wyoming Royalty Payment Act (which applies to both private and governmental leases) says nothing about reimbursements by a purchaser for severance taxes paid by a producer or any royalty consequences of such reimbursements. The only mention of severance taxes in that statute is the requirement that information regarding "[t]he total amount of state severance, ad valorem and other production taxes" (along with several other items of information) be included on the check stub or attachment to the form of payment whenever payment is made for oil or gas production to an interest owner. Wyo. Stat. § 30-5-305(b)(5). The Wyoming Royalty Payment Act therefore had no bearing on the *Cities Service* decision.

> agreements shall not be less than the price received for production on federal leases. It certainly does not require that all elements of royalty valuation be the same for state leases as for federal leases.

871 P.2d at 515.[27] Justice Durham appears to assert that the Federal floor proviso prohibited the lessee of a state lease from entering into a contract to sell gas produced from (or allocated to) the state lease at a price lower than the price at which a Federal lessee in the same field had agreed to sell gas. That is the position EOG took in its briefs in the instant appeal. EOG argued that "[t]here is no dispute this clause [*i.e.*, the Federal floor proviso] requires that the price paid for gas produced from a SITLA leaseCthe sales priceCmay not be less than the price paid for gas produced from a federal lease." EOG Opening Brief, p. 8; *see also* EOG Response Brief, p. 5.[28] That is also the position Enron took in its petition for rehearing before the Utah Supreme Court. In its petition for rehearing, after quoting the Federal floor proviso, Enron argued:

> Thus, it is the price specified in an approved natural gas sales contract that must be at least the price for which production from United States oil and gas leases is sold. . . . As pointed out by the dissent, this provision relates only to the price paid under an approved natural gas contract, not to the ultimate royalty paid to the Division.

Petition for Rehearing, *Enron Oil & Gas Company v. State of Utah, Department of Natural Resources*, *Division of State Lands and Forestry*, No. 910057 (Supreme Court of Utah, Feb. 2, 1994) (SITLA Opening Brief, Exhibit A), p. 10 (emphasis in original).[29] The Utah Supreme Court denied the petition.

At oral argument in the instant appeal, however, EOG abandoned that position and expressly stated that it was not arguing that the subject leases prohibit the lessee from entering into a contract to sell gas at a lower price than the price at which a Federal lessee in the same field sells gas. EOG instead argues that the stated contract price used as the beginning point for royalty valuation under a State lease must be increased to the price at which like-quality gas produced from Federal leases in the same field is sold if that price is higher, but once that adjustment is made, the requirements of Federal royalty valuation rules do not apply and the "value at the well" royalty clause entitles EOG to deduct costs that would not be deductible under the Federal valuation rules.

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[27] This statement shows that Justice Durham understood the majority holding to be that the Federal royalty valuation rules apply under the Federal floor proviso.

[28] It is not clear why EOG says that "there is no dispute" in this respect; SITLA offers a very different interpretation of the proviso.

[29] Significantly, Enron read the majority opinion as requiring that production from a state lease be valued under the Federal royalty valuation rules to comply with the "Federal floor" proviso. *Id.*, pp. 10-11. In other words, Enron read the majority opinion in the same way SITLA reads it.

EOG's current position is consistent with Justice Durham's assertion that the Federal floor proviso "does not require that all elements of royalty valuation be the same for state leases as for federal leases." However, EOG's current position is not the interpretation Justice Durham advanced. Even setting aside the fact that the majority rejected her position, the argument in Justice Durham's dissent is at best very weak support for EOG's argument.

Further, nothing in the majority opinion gives any indication that the majority would have agreed with EOG's current argument. Indeed, if the point of the Federal floor proviso is that the royalty owed to the State under a state lease cannot be less than the royalty owed to the United States on gas of like grade and quality produced from Federal leases in the same fieldCas the majority held in *Enron* and the Wyoming Supreme Court expressly held in *Cities Service* with virtually identical clausesCthe reading EOG now advances is inconsistent with the *Enron* holding.

3. Application of Principles of Contract Interpretation

We may then ask whether EOG's reading of the Federal floor proviso finds any support in established principles of contract interpretation. In *Heiner v. S.J. Groves Sons Co.*, 790 P.2d 107, 110 (Utah Ct. App. 1990), cited in EOG's opening brief at p. 4, the Utah Court of Appeals noted that "[t]he general principles governing the interpretation of contracts apply to documents conveying mineral interests" and that "[t]he cardinal rule is to give effect to the intentions of the parties and, if possible, to glean those intentions from the contract itself."[30]

Heiner was not a mineral lease case, but mineral leases do convey interests in the subsurface mineral estate. In *Sears v. Riemersma*, 655 P.2d 1105, 1107-1108 (Utah 1982), the Utah Supreme Court held that "[t]he primary rule in interpreting a contract is to determine what the parties intended by looking at the entire contract and all of its parts in relation to each other, giving an objective and reasonable construction to the contract as a whole."[31]

In *Plateau Mining Co. v. Division of State Lands*, 802 P.2d 720 (Utah 1990), lessees of state coal leases issued in the 1960s disputed the interpretation of the royalty clause of the leases. The leases required a royalty at the higher of 15 cents per ton of coal produced, or at the rate prevailing, at the beginning of the quarter for which payment is being made, for Federal lessees of land of similar character under coal leases issued by the United States at that time. In 1976, Congress amended section 7 of the MLA, 30 U.S.C. § 207, to provide for royalty of not less than 12½ percent of the value of coal as defined by regulation, except that the Secretary could determine a lesser amount for coal produced from underground mines. The Department of the

[30] Quoting *LDS Hosp. v. Capitol Life Ins. Co.*, 765 P.2d 857, 858 (Utah 1988), and *G.G.A., Inc. v. Leventis*, 773 P.2d 841, 845 (Utah Ct. App. 1989).

[31] Citing *Mark Steel Corp. v. Eimco Corp., Utah*, 548 P.2d 892 (1976); *Thomas J. Peck Sons, Inc. v. Lee Rock Products, Inc.*, 30 Utah 2d 187, 515 P.2d 446 (1973); and *Cornwall v. Willow Creek Country Club*, 13 Utah 2d 160, 369 P.2d 928 (1962).

Interior thereafter promulgated regulations prescribing a royalty rate of eight percent of the value of the coal produced for new leases of underground mines.[32]

The lessees continued to pay royalty at the cents-per-ton rate. In 1985, the State demanded royalties retrospectively based on the higher Federal eight percent rate. The trial court ruled that the alternative provision for royalty at the rate prevailing for Federal leases issued at the time was ambiguous, and therefore unenforceable, because it was based on factors not immediately capable of definitive determination. The Utah Supreme Court reversed and held that "a contract provision is not necessarily ambiguous just because one party gives that provision a different meaning than another party does. To demonstrate ambiguity, the contrary positions of the parties must each be tenable." 802 P.2d at 725-726.[33] Similarly, in *Cities Service*, in considering a substantively identical "Federal floor" proviso, the Wyoming Supreme Court explained (838 P.2d at 151):

> The fact that the parties to the leases disagree as to the contractual basis for royalty calculation does not necessarily indicate ambiguity. *Amoco Production Co. v. Stauffer Chemical Co. of Wyoming*, 612 P.2d 463, 465 (Wyo. 1980) (citing *Homestake-Sapin Partners v. United States*, 375 F.2d 507 (10th Cir. 1967)). We affirm our decision in *Moncrief* and agree with the parties' assertions in this case that the royalty clause taken as a whole and the "federal floor" provision taken separately are unambiguous.

At oral argument in the instant appeal, both parties expressly took the position that the lease instruments are not ambiguous.

Therefore, we must "determine what the parties intended by looking at the entire contract and all of its parts in relation to each other, giving an objective and reasonable construction to the contract as a whole." *Sears v. Riemersma*, *supra*. That analysis also will reveal whether EOG's interpretation is tenable.[34]

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[32] Pub. L. No. 94-377, Aug. 4, 1976, 90 Stat. 1083; 43 C.F.R. § 3473.3-2(a)(3) (1979) (44 Fed. Reg. 42584, 42643, 42647-42648 (July 19, 1979)).

[33] Citing *Buehner Block Co. v. UWC Assocs.*, 752 P.2d 892, 895 (Utah 1988), and *Grow v. Marwick Dev., Inc.*, 621 P.2d 1249, 1252 (Utah 1980). The question of what is the "rate prevailing . . . for federal leases . . . issued by the United States at that time" was resolved in the subsequent appeal after remand of the *Plateau Mining* decision in *Trail Mountain Coal Co. v. Division of State Lands*, 884 P.2d 1265 (Utah Ct. App. 1994). The subsequent Utah Supreme Court decision in that appeal, *Trail Mountain Coal Co. v. Division of State Lands*, 921 P.2d 1365 (Utah 1996), discussed below, addressed statute of limitations and late payment interest issues and did not address issues relevant to interpretation of the royalty clause.

[34] For the reasons explained above, the Utah Supreme Court's majority opinion in *Enron*Cparticularly in conjunction with the Wyoming Supreme Court's interpretation in *Cities Service*Csupports SITLA's interpretation, which therefore is tenable.

Looking first to the words of the lease instrument itself, EOG's interpretation rests on the assertion that the requirement in the Federal floor proviso that "in no event shall the price for gas be less than that received by the United States of America for its royalties" refers to the price at which a Federal lessee—not the lessor, the United States—sells the gas produced from the lease. That assertion is flawed.

EOG's reading is not what the words of the Federal floor proviso say. The Federal floor proviso, on its face, does not refer to the price at which a Federal lessee sells production from Federal leases in the field. It speaks in terms of the "price . . . received by the United States of America for its royalties." The United States does not sell gas produced by the lessee. Nor does the United States sell its royalty interest, or the royalty payments that it receives, for a "price."

Under Federal lease terms and the governing leasing statute, the United States receives royalty calculated as a percentage of the value of the production. The wording in the subject state leases that immediately precedes the Federal floor proviso in the same sentence, after establishing the royalty as 12½ percent "of the reasonable market value," further provides that where the lessee sells under a contract approved by the lessor (the State), "the <u>reasonable market value</u> of such gas for the purpose of determining the royalties payable hereunder, <u>shall be the price at which the production is sold</u>" [emphasis added]Cthus establishing an approved contract price as the measure of royalty value.[35] In adding that "in no event shall the price for gas be less than that received by the United States of America for its royalties," the intent appears to be to refer to "price" as a measure of value. Though the Federal floor proviso applicable to unprocessed gas and residue gas is phrased awkwardly in terms of "price," the immediate antecedent to that term in the very same sentence is a reference to price as a measure of value.

In then looking beyond the language of the gas Federal floor proviso to the entire contract and all of its parts in relation to each other, so as to give an objective and reasonable construction to the contract as a whole, the Federal floor provisos for NGLs and crude oil are of critical importance. The NGL Federal floor proviso, as quoted above, provides that the market value of processed products used in the computation of royalties under the state lease "shall not be less than the value used by the United States in its computation of royalties on similar products . . . ." The crude oil Federal floor proviso, as also quoted above, provides that "in no event shall royalties be based upon a market value less than that used by the United States in the computation of royalties, if any, paid by this LESSEE to the United States" on oil of like grade and gravity produced in the same field.

Though the crude oil proviso, unlike the gas and NGL provisos, is limited to royalties paid to the United States under Federal leases by the particular state lessee, both of these provisions plainly require a minimum royalty value of production determined under the Federal royalty valuation rules. Given that this is the clear intent and purpose of these two provisos, it is difficult to read the lease as a whole as contemplating a different intent for unprocessed gas and

[35] In the context of this sentence, a "contract approved by the lessor" means the State as lessor has approved the contract as accurately representing market value; it does not imply that the State had to approve the lessee entering into the contract in the first instance. Lessees are not required to seek state approval before entering into gas sales contracts.

residue gas. The Utah Supreme Court majority opinion in *Enron* reinforces and supports reading the intent of the gas Federal floor proviso as the same as the NGL and crude oil provisos.

Further, it is not necessary for the provisos to be worded identically for them to have the same intent and purpose. The NGL and crude oil provisos demonstrate this, because they are not worded identically to each other but nevertheless have the same meaning and purpose.

Moreover, EOG has not suggested, and the Board is unable to discern, any state policy or purpose that would be served by reading the intent of the gas Federal floor proviso much more narrowly than the intent of the NGL and crude oil provisos. In the absence of such an identifiable policy or purpose, the only reasonable conclusion, in looking at these provisions in relation to each other and reading the lease as a whole, is that all three Federal floor provisos serve the same purpose. That purpose is to ensure that royalty is not paid to the State under a state lease on a value of production less than that on which royalties are paid on production from Federal leases in the same field.

Even in the 1950s, when the earliest of the leases involved in this appeal were issued, it was probable, and undoubtedly well understood, that in the majority of situations state leases would be part of the same field as Federal leases. This is due to the "patchwork" ownership pattern of disjoined sections 2, 16, 32, and 36 of a township being owned by the State.[36] Consequently, State-owned sections generally will be mostly surrounded by Federally-owned mineral estate. That is the case in the instant appeal. Thus, protecting the State's interest by ensuring that the State receives no less in royalty under its leases than the Federal government receives under its leases in the same field makes perfect sense.

In addition, EOG's interpretation would give rise to serious problems in practice. As quoted above, the Federal floor proviso refers to royalties that the United States receives "from gas of like grade and quality from the same <u>field</u>." (Emphasis added.) The proviso does not refer to gas of like grade and quality from the same unit or pool. Indeed, state law implicitly recognizes that a field generally will encompass a larger area than a unit or pool.[37] The State has

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[36] *See* Utah Enabling Act, July 16, 1894, ch. 138 § 6, 28 Stat. 107, as amended by Act of May 3, 1902, ch. 683, §§ 1, 2, 32 Stat. 188 , 189, 43 U.S.C. § 853. The mineral estate ownership pattern could, of course, change in any particular situation if the State acquired the mineral interest in additional parcels after the enactment of 43 U.S.C. § 853. That is the case in the Natural Buttes Field, where the State owns the mineral interest in a number of additional parcels. *See* APP 000505.

[37] Utah Code Ann. § 40-6-2 and Utah Admin. Code R649-1-1 (the definitions section in the regulations promulgated under the authority of Utah Code Ann. § 40-6-5) both define "pool" as follows: "'Pool' means an underground reservoir containing a common accumulation of oil or gas or both. Each zone of a general structure that is completely separated from any other zone in the structure is a separate pool." Utah Admin. Code R649-1-1 further defines "field" as follows: "'Field' means the general area underlaid by one or more pools." Utah Code Ann. § 40-6-8(1) provides for unitization under state law of "of one or more pools or parts of them in a field." The State's authority to name oil and gas fields is currently found at Utah Admin. Code R649-2-7.1.

designated the field within which all but one of the subject leases is situated, *i.e.*, the Natural Buttes Field. As noted in the Findings of Fact above, the Natural Buttes Field includes 10 other units that include, and consist predominantly of, Federal leases. EOG is the operator of only one of those units.

For EOG to apply its interpretation of the Federal floor proviso, it would have to know the prices at which the gas produced from or allocated to all the Federal leases in the field was sold. While EOG, as the operator of the Chapita Wells Unit and the Stagecoach Unit, knows the price at which most of the production allocated to both the Federal and state leases within those two units is sold (except for the portion of gas taken in kind by other working interest owners and sold by them), by what means would EOG know the prices at which the operators of nine other units sold gas produced from or allocated to Federal leases in those units? By what means would EOG know the prices at which gas produced from non-unitized Federal leases in the field, of which EOG is not the operator, was sold? As noted previously, the lessee of a state lease does not have legal authority to compel a lessee of a Federal lease in the field to disclose the price at which the Federal lessee sells its production.

Moreover, different Federal lessees in the same field may sell, and likely are selling, production at different prices. In that event, even if the lessee of the state lease could find out what those prices are, which of those prices would be the floor up to which the state lessee's sales price would have to be increased, which EOG then would use as the beginning point for royalty calculation under its theory? The highest price at which any of the Federal lessees sells gas? A volume- weighted average of all of them? The lowest price?[38]

In short, EOG's current interpretation of the Federal floor proviso would be impossible to apply in practice.

For all of these reasons, EOG's current interpretation of the Federal floor proviso is neither reasonable nor tenable. The only reasonable construction of the unusual phraseology of the Federal floor proviso for unprocessed gas and residue gas in the context of the entire contract, and all of its parts in relation to each other, is that its purpose and intent is the same as the purpose of the other two Federal floor provisos for NGLs and crude oilC*i.e.*, that the State should not receive less royalty than the Federal government receives for production from or allocated to its leases in the same field, and that the term "price" in this clause refers to the value on which royalty is calculated. In other words, the clause is intended to ensure that royalty is paid to the State on a value not less than the value on which royalties are paid on production from Federal leases in the same field.

4. Revised Royalty Clause in Newer State Oil and Gas Leases

[38] The only situation in which EOG's interpretation could work is if the lessee under a state lease is the only working interest owner in the field and is selling all the gas produced from the entire fieldCincluding production from both state leases and the Federal leasesCand then sells all the production from both the state leases and the Federal leases in the field under one contract. That is not the case in the instant appeal, and would not be expected to be the case generally.

EOG observes that the relevant portion of the royalty clause in newer state oil and gas lease forms has been changed to read:

> It is the intent of Lessor and Lessee that the calculation of the value of oil and gas for royalty purposes under this Lease be consistent with federal regulations governing the valuation of federally owned oil and gas and associated hydrocarbons (including but not limited to federal law and regulations with respect to the Lessee's obligation to place oil and gas into marketable condition prior to royalty settlement), except where this Lease expressly provides otherwise. In no event shall the value of oil or gas used for calculation of royalties under this Lease be less than the value which would be obtained were federal royalty valuation regulations in existence at the time of production applied in the calculation of royalties and applicable deductions under this Lease.

EOG then argues that this language "confirms [SITLA's] more recent intent that lessees calculate natural gas royalties consistent with federal regulations and expressly references the requirement of placing gas in 'marketable condition' prior to royalty settlement. . . . That intent and language, however, are not part of EOG's leases subject to the 2018 Audit Report." EOG Opening Brief, p. 4; *see also* EOG Response Brief, pp. 1 and 9.

EOG's argument that the express reference to Federal valuation rules in the new lease form somehow implies that the intent of the subject lease instruments is not to require a minimum valuation determined according to Federal valuation rules is not logically valid. The fact that the new state oil and gas lease form sets out in more and different words the express obligation that royalty be paid on no less than the value determined under Federal oil and gas lease royalty valuation rules, and expressly refers to the requirement that the lessee put production into marketable condition, does not imply that the Federal floor proviso in the earlier lease forms at issue in this matter was not intended to, or does not, achieve the same result. The prior lease form must be interpreted on its own under applicable principles. EOG acknowledged that principle at oral argument. The fact that the new lease form is easier to interpret or may use less awkward phraseology carries no implication one way or the other with respect to the meaning of the lease form at issue. *See Mason v. United States*, 615 F.2d 1343, 1348 n. 7 (Fed. Cir. 1980), and cases cited.

In sum, the gas Federal floor proviso requires royalty payment on the basis of no less than the value of the gas production determined under Federal valuation regulations. The terms of EOG's state leases require it to pay royalty on the higher of the "market value at the well" or the value determined under the rules applicable to Federal leases. That is the bargain to which the original lessees agreed, and which EOG assumed when it acquired the leases.

B. Requirements under the Federal Valuation Rules

1. General Valuation Principles

The current Federal onshore oil and gas royalty valuation rules contain separate provisions for unprocessed gas and processed gas. Broadly speaking, under the rules in effect since 1988, for residue gas and gas plant products sold under an arm's-length contract, the lessee=s gross proceeds, with certain specified exceptions, are accepted as the royalty value.[39] As noted previously in the discussion of the *Enron* Utah Supreme Court case, the lessee's gross proceeds, less applicable allowances, are always the minimum value for royalty purposes.

The rules also provide for allowances (deductions) for the costs of transporting gas to a downstream point of sale off the lease.[40] Specifically, where the value of gas has been determined at a point (*e.g.*, a sales point) off the lease, the lessee may deduct the reasonable actual costs of transporting unprocessed gas, residue gas, and gas plant products "from a lease to a point off the lease including, if appropriate, transportation from the lease to a gas processing plant off the lease and from the plant to a point away from the plant." 30 C.F.R. § 1206.156(a) (2011-2020), formerly 30 C.F.R. § 206.156(a) (1988-2010). Under subsection (c), unless ONRR grants specific approval, a transportation allowance may not exceed 50 percent of the value of the unprocessed gas, residue gas, or gas plant product.

For processed gas, *i.e.*, residue gas and gas plant products, the rules provide for allowances for the cost of processing for the extraction of valuable products such as NGLs.[41] Processing costs must be allocated among the gas plant products, and may not be applied against the value of the residue gas. NGLs are considered as one product. Ordinarily, the processing allowance deduction on the basis of an individual product may not exceed 66⅔ percent of the value of each gas plant product (with value first reduced for any transportation allowances related to post-processing transportation).[42]

The rule codification in 30 C.F.R. Part 1206 is part of ONRR's regulations, which were transferred from regulations of the former Minerals Management Service (MMS) in 2010 following the division of the MMS into three agencies.[43] ONRR is MMS' successor agency in royalty management functions.[44]

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[39] 30 C.F.R. §1206.153(b) (2011-2020); former § 206.153(b) (1988-2010).

[40] 30 C.F.R. §§ 1206.156-1206.157 (2011-2020); former §§ 206.156-206.157 (1988-2010).

[41] 30 C.F.R. §§ 1202.151(a) and (b) (2011-2020), formerly § 202.151(a) and (b) (1988-2010), and 1206.158-1206.159 (2011-2020), formerly §§ 206.158-206.159 (1988-2010).

[42] 30 C.F.R. § 1206.158(b) and (c) (2011-2020), formerly § 206.158(b) and (c) (1988-2010).

[43] 75 Fed. Reg. 61051, 61055, 61066 (Oct. 4, 2010).

[44] On October 1, 2020, ONRR published proposed revisions to the Federal gas royalty valuation regulations to address certain specific issues. 85 Fed. Reg. 62054. ONRR published a final rule on January 15, 2021, which became effective on February 16, 2021. 86 Fed. Reg. 4655. Under the new rule, if the lessee or its affiliate sells residue gas or gas plant products under an arm's-

2. The "Marketable Condition" Rule

The regulations also require the lessee to put production into marketable condition at no cost to the lessor. Title 30 C.F.R. § 1206.153(i) (2011-2020), applicable to processed gas, provides in relevant part that "[t]he lessee must place residue gas and gas plant products in marketable condition and market the residue gas and gas plant products for the mutual benefit of the lessee and the lessor at no cost to the Federal government."[45] The identical "marketable condition" rules have been part of the MMS valuation regulations since 1988[46] (and continue in the new rule effective February 16, 2021[47]).

The 1988 rules continued the marketable condition requirements governing onshore Federal oil and gas leases that had been in force since 1942Cmore than a decade before the first of the State leases involved in this appeal were issued. U.S. Geological Survey (USGS) regulations at former 30 C.F.R. § 221.31 (7 Fed. Reg. 4132, 4235 (June 2, 1942)), provided in relevant part that "the lessee shall put into marketable condition, if commercially feasible, all products produced from the leased land and pay royalty thereon without recourse to the lessor for deductions on account of costs of treatment . . . ." This language remained unchanged until 1982, and therefore was in force at the time ML 1299, ML 3077, ML 3078, and ML 3355 involved in this appeal were issued.[48] The marketable condition rule has been uniformly upheld and applied in numerous cases cited below.

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length contract, the gross proceeds under the first arm's-length contract are accepted as the royalty value. 30 C.F.R. § 1206.142(c) (2021). The transportation allowance rules are found in new 30 C.F.R. §§ 1206.152-1206.158 (2021), and the processing allowance rules are found in new 30 C.F.R. §§ 1206.159-1206.165. The new rule does not affect the instant case because the audit period involved here ended on December 31, 2017. For convenience, we will continue to refer to the 2011-2020 codified rule section numbers in the present tense.

[45] The marketable condition rule for unprocessed gas is found at 30 C.F.R. § 1206.152(i) (2011-2020). For a brief period, these requirements were recodified effective January 1, 2017, to 30 C.F.R. § 1206.146 (2017) as part of a broader Federal royalty valuation rules reform undertaken near the end of the Obama presidential administration. 81 Fed. Reg. 43338, 43383 (July 1, 2016). On August 7, 2017, this rule was repealed and the previous rules were reinstated effective September 6, 2017. 82 Fed. Reg. 36934, 36966, 36968. The requirement for the lessee to put production into marketable condition remained unchanged throughout.

[46] *See* former 30 C.F.R. §§ 202.151(b), 206.152(i), 206.153(i), and 206.158(d)(1) (1988-2010); 53 Fed. Reg. 1230, 1271, 1274, 1277, 1281 (Jan. 15, 1988), as amended at 65 Fed. Reg. 65753, 65762 (Dec. 16, 1997).

[47] New 30 C.F.R. § 1206.146 (2021).

[48] This portion of former section 221.31 was recodified into MMS regulations after MMS was formed in 1982 (and took over USGS' mineral leasing functions) as former 30 C.F.R. § 221.36(a) (47 Fed. Reg. 47765, 47771 (Oct. 27, 1982)), and then redesignated to BLM onshore oil and gas operating regulations as 43 C.F.R. ' 3162.7-1 (48 Fed. Reg. 36582, 36583 (Aug. 12,

3. Functions or Operations Necessary to Put Gas into Marketable Condition

The valuation regulations in effect since 1988 also include an express definition of "marketable condition": "*Marketable condition* means lease products which are sufficiently free from impurities and otherwise in a condition that they will be accepted by a purchaser under a sales contract typical for the field or area." 30 C.F.R. § 1206.151 (2011-2020); former 30 C.F.R. § 206.151 (1988-2010).[49]

This definition implements the principle that making production marketable involves more than simply selling it. As the court explained in *California Co. v. Udall*, 296 F.2d 384, 387-388 (D.C. Cir. 1961):

> Theoretically, any gasCany "production"Cis "marketable." We can assume that, if the price were low enough to justify capital expenditures for conditioning equipment, someone would undertake to buy low pressure gas having a high water content. A lessee who sold unconditioned gas at such a price would, in a rhetorical sense, be fulfilling his obligation to "market" the gas, and by thus saving on overhead he might find such business profitable. There is a clear difference between "marketing" and merely selling. For the former there must be a market, an established demand for an identified product. We suppose almost anything can be sold, if the price is no consideration. In the record before us there is no evidence of a market for the gas in the condition it comes from the wells. The only market, as far as this record shows, was for this gas at certain pressure and certain minimum water and hydrocarbon content. [Footnote omitted.]

Two USGS regulations applicable to Federal onshore leases published in 1977[50] that supplemented the rules codified at former 30 C.F.R. part 221 summarized the functions necessary to put production into marketable condition, consistent with administrative and judicial decisions cited below that predated these rules. NTL-5 provided:

> Gross proceeds [the minimum value for royalty purposes] include, but are not limited to, tax reimbursements and payments to the

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1983)), which continues in force today.

[49] The identical definition continues in the 2021 rule. 30 C.F.R. § 1206.20 (2021).

[50] "Notice to Lessees and Operators of Federal Onshore Oil and Gas Leases (NTL-1)," 42 Fed. Reg. 4546 (Jan. 25, 1977), and "Notice to Lessees and Operators of Federal and Indian Onshore Oil and Gas Leases (NTL-5)," 42 Fed. Reg. 22610 (May 4, 1977). Though not codified to the Code of Federal Regulations, they were adopted after notice and comment procedures. NTL-1 and NTL-5 were both superseded when MMS promulgated the 1988 royalty valuation rules.

> lessee or operator for the performance of certain services such as measuring, field gathering, compressing, sweetening, and dehydrating which are necessary to place the gas into marketable condition and which the lessee or operator is obligated to perform at no cost to the lessor. Likewise, no deductions will be allowed for the uncompensated cost of placing the gas into marketable condition.

42 Fed. Reg. at 22611 (emphasis added). NTL-1 contained similar language. 42 Fed. Reg. at 4548. Further, the processing allowance rules in effect since 1988 provide:

> Except as provided in paragraph (d)(2) of this section, no processing cost deduction shall be allowed for the costs of placing lease products in marketable condition, including dehydration, separation, compression, or storage, even if those functions are performed off the lease or at a processing plant. Where gas is processed for the removal of acid gases, commonly referred to as "sweetening," no processing cost deduction shall be allowed for such costs unless the acid gases removed are further processed into a gas plant product.[51] In such event, the lessee shall be eligible for a processing allowance as determined in accordance with this subpart.

30 C.F.R. § 1206.158(d)(1) (2011-2020); formerly 30 C.F.R. § 206.158(d)(1) (1988-2010) (emphasis added).[52] In addition, the rule governing the processed gas volumes on which royalty is due, which allows royalty-free use of a reasonable amount of residue gas for plant operations, goes on to provide that "no allowance shall be made for boosting [*i.e.*, compressing] residue gas or other expenses incidental to marketing . . . ." 30 C.F.R. § 1202.151(b) (2011-present), formerly 30 C.F.R. § 202.151(b) (1988-2010). Moreover, the preamble discussion of the marketable condition requirements in the 1988 rule explained that "[s]everal State, Indian, and individual commenters agree with MMS's proposed provision that costs such as those for compression to meet pipeline pressure requirements to place the gas in marketable condition should be borne by the lessee." 53 Fed. Reg. at 1252 (emphasis added).

Thus, treating gas to put it into marketable condition will involve gathering, compression, dehydration, and sweetening/desulphurization, as the particular circumstances of the gas produced necessitate. In almost all situations, this will mean that gas must be compressed, dehydrated, and sweetened to meet the minimum pressure requirements, and maximum water and acid gas content requirements, of the transporting pipeline. The cases cited in the note below provide numerous examples.[53]

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[51] *E.g.*, elemental sulfur derived from H_2S and then sold.

[52] *See also* new 30 C.F.R. § 1206.159(d)(1) and (d)(2) (2021).

[53] *See Devon Energy Corp. v. Kempthorne*, 551 F.3d 1030 (D.C. Cir. 2008) (compression, dehydration, and removal of CO_2 from coalbed methane to meet pipeline requirements); *Amoco*

The application of these principles to the gas involved in this appeal under the undisputed and stipulated facts in the record will be discussed below.

II. <u>The Lessee's Implied Covenant to Market and Its Relationship to the Value at the Well Provision</u>

Because the Federal floor proviso controls, the analysis in Part I above applies regardless of whether the Utah Supreme Court would agree with the apparent majority view of courts in other states and adopt EOG's reading of the value at the well provision in the subject lease instruments. Under EOG's reading and the apparent majority view, absent the Federal floor

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Production Co. v. Watson, 410 F.3d 722 (D.C. Cir. 2005) (affirming *Amoco Production Co. v. Baca*, 300 F. Supp. 2d 1 (D.D.C. 2003)) (removal of CO_2 from coalbed methane; contracts for treated gas were typical for production from the field or area though some untreated gas was used locally); *Amerada Hess Corp. v. Department of the Interior*, 170 F.3d 1032 (10th Cir. 1999) (gathering and compression, and reimbursements by the purchaser for those costs under NGPA section 110 as part of the lessee's gross proceeds); *Mesa Operating Limited Partnership v. Department of the Interior*, 931 F.2d 318 (5th Cir. 1991) (gathering, compression, dehydration, and sweetening, and reimbursements for those costs as part of gross proceeds); *California Co. v. Udall*, 296 F.2d 384 (D.C. Cir. 1961) (affirming *California Co. v. Seaton*, 187 F. Supp. 445 (D.D.C. 1960), upholding *The California Company*, 66 I.D. 54 (1959)) (gathering to delivery point in the field, and compression and dehydration to pipeline requirements); *Citation Oil & Gas Corp. v. U.S. Department of the Interior*, 448 F. App'x. 441 (5th Cir. 2011) (compression and treatment costs, where performed by initial purchaser before processing and resale); *Burlington Resources Oil & Gas Co. v. U.S. Department of the Interior*, No. 13-CV-0678-CVE-TLW (N.D. Okla. 2014) (upholding *Burlington Resources Oil & Gas Co.*, 183 IBLA 333 (2013)) (compression, dehydration, and sweetening, where sweetening and dehydration were performed by the initial purchaser before processing and resale); *Bailey D. Gothard v. United States*, No. CV 98-103-BLG (D. Mont. June 29, 1999) (upholding *Bailey D. Gothard*, 144 IBLA 17 (1998)) (gatherer bought uncompressed gas, compressed it, and resold it to the pipeline; price differential covered the compression and gathering costs; no market for ungathered and uncompressed gas, and gatherer's purchase at discounted price did not mean gas was marketable in that condition); *Branch Oil and Gas Co.*, 144 IBLA 304 (1998) (same); and *Branch Oil and Gas Co.*, 143 IBLA 203 (1998) (same); *XTO Energy, Inc.*, 185 IBLA 219 (2015) (gathering and compression to pipeline pressure after processing; contracts for sale in distant market typical for field or area); *Encana Oil & Gas (USA), Inc.*, 185 IBLA 133 (2014) (compression, dehydration, and CO_2 removal to meet pipeline requirements); *J-W Operating Co.*, 159 IBLA 1 (2003) (compression to pipeline pressure and dehydration to market specifications); *Texaco Inc.*, 134 IBLA 109 (1995) (price reduced by purchaser's fee to remove H_2S); *Apache Corp.*, 127 IBLA 215 (1993) (same); *Exxon Co. USA*, 121 IBLA 234 (1991) (similar; purchaser's acceptance of untreated gas did not mean the gas was marketable in its natural state); *R. E. Yarbrough & Co.*, 122 IBLA 217 (1992) (gathering, and compression and dehydration to pipeline requirements performed by purchaser who reduced price paid to lessee by those costs); *The Texas Co.*, 64 I.D. 76 (1957) (gathering to the central point in the field and compression to pipeline pressure); *Placid Oil Co.*, 70 I.D. 438 (1963) (same).

proviso, EOG would be entitled to deduct the costs of gathering, compression, treatment, and marketing—as well as processing and transportation—incurred after gas surfaces at the wellhead. In view of the analysis in Part I, it is not strictly necessary for the Board to decide this question here because the Federal floor proviso does require EOG to put production into marketable condition at no cost to the State as lessor. However, in the event that the Utah Court of Appeals or the Utah Supreme Court were to disagree with the Board regarding the meaning of the Federal floor proviso, the court would reach the issue of the meaning of the value at the well provision. Therefore, it is appropriate for the Board to offer its analysis of this issue, at least in brief. For the reasons explained below, the Board believes that it is not at all clear that the Utah Supreme Court would adopt the apparent majority view. In the Board's opinion, there is substantial reason to believe that the Utah Supreme Court would adopt the apparent minority view.

An implied covenant to market production for the mutual benefit of the lessee and lessor is almost a universal characteristic of oil and gas leases.[54] The question here is whether this implied covenant encompasses a duty to make the production marketable, *i.e.*, to treat production to put it into marketable condition. Both EOG and SITLA acknowledge that the Utah Supreme Court has not decided that issue.

As noted previously, several states have taken the view that a "value at the well" (or "market price at the well") royalty clause allows a lessee to deduct costs of treating production to put it in marketable condition, including California, Texas, Louisiana, North Dakota, and Kentucky.[55] States that have taken the view that the implied covenant to market obligates the lessee to put production in to marketable condition at its own expense include Oklahoma, Colorado, Kansas, and West Virginia.[56]

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[54] *See, e.g.*, 5 Williams and Meyers, *Oil and Gas Law*, §§ 853-858 (1996); Hemingway, *Law of Oil and Gas* (3rd Ed. 1991), Ch. 8, § 8.9(C) at 577; *Mittelstaedt v. Santa Fe Minerals, Inc.*, 954 P.2d 1203, 1205-06 (Okla. 1998); *Watts v. Atlantic Richfield Co.*, 115 F.3d 785, 794 (10th Cir. 1997) and cases cited; *Klein v. Arkoma Production Co.*, 73 F.3d 779 (8th Cir. 1996); *Rogers v. Westerman Farm Co.*, 29 P.3d 887 (Colo. 2001); *Garman v. Conoco, Inc.*, 886 P.2d 652, 657 (Colo. 1994); *Davis v. Cramer*, 808 P.2d 358 (Colo. 1991); *Martin v. Glass*, 571 F. Supp. 1406, 1415-16 (N.D. Tex. 1983); *Amoco Production Co. v. First Baptist Church of Pyote*, 579 S.W.2d 280 (Tex. Civ. App. 1979), *writ ref'd n.r.e.*, 611 S.W.2d 610 (Tex. 1981); *Ashland Oil & Refining Co. v. Staats, Inc.*, 271 F. Supp. 571, 576 (D. Kan. 1967).

[55] *See* cases cited in note 22, *supra*. The apparent majority approach may not be as much of a majority as EOG seems to believe; some courts in their opinions have combined (or confused) costs of processing and costs of treatment necessary to make gas marketable.

[56] *See Wood v. TXO Production Corp.*, 1992 OK 100, 854 P.2d 880 (1993); *Garman v. Conoco, Inc.*, 886 P.2d 652 (Colo. 1994); *Rogers v. Westerman Farm Co.*, 29 P.3d 887 (Colo. 2001); *Gilmore v. Superior Oil Co.*, 192 Kan. 388, 388 P.2d 602 (1964); *Schupbach v. Continental Oil Co.*, 193 Kan. 401, 394 P.2d 1 (1964); and *Estate v. Columbia*, 219 W. Va. 266, 633 S.E.2d 22 (2006). As noted above, Wyoming requires lessees to bear the costs of making production marketable by statute. Wyoming Royalty Payment Act of 1982, Wyo. Stat. §§ 30-5-301 - 30-5-305. (*See* the definitions of "lessee," "lessor," "royalty," and "costs of production" in section 30-

A. EOG's Arguments

EOG offers three arguments in support of the proposition that the Utah Supreme Court would adopt the apparent majority line of cases.

1. The U.S. Magistrate Judge's 2012 Decision in *Emery Resource Holdings* and the Utah Supreme Court's 1962 Decision in *Rimledge Uranium Mining Corp.*

EOG relies on the decision of a U.S. Magistrate Judge in *Emery Resource Holdings, LLC v. Coastal Plains Energy, Inc.*, 915 F. Supp. 2d 1231 (D. Utah 2012), and the Utah Supreme Court's decision in a uranium ore case, *Rimledge Uranium Mining Corp. v. Federal Resources Corp.*, 13 Utah 2d 329, 374 P.2d 20 (1962). In *Emery Resource Holdings,* the royalty clauses of the three private leases involved bore some similarity to the royalty clause at issue in this appeal, but they were not identical to it or to each other. Two of the three royalty clauses referred specifically to proceeds derived from sales occurring at the well. The court construed the third royalty clause to also refer to the sale of gas in the condition in which it was produced from the wells. The Magistrate Judge relied on the apparent majority line of cases in rejecting the lessors' argument that the implied covenant to market obligated the lessee to put production into marketable condition at its own expense.

Beyond the differences between the more specific royalty clauses in the leases involved in that case and the state leases involved here, a Federal court's speculation as to how a state supreme court would rule on an unresolved issue of state law is not binding. It is well-settled that, as the Seventh Circuit observed: "State courts are not bound by federal courts' interpretations of state law. A state judge will give such interpretations no more weight than their persuasiveness earns them." *Diginet, Inc. v. Western Union ATS, Inc.*, 958 F.2d 1388, 1395 (7th Cir. 1992).[57] The Utah Court of Appeals acknowledged this principle in *Deleeuw v. Nationstar Mortgage LLC*, 2018 UT App. 59, 424 P.3d 1075 (Utah Ct. App. 2018) (though the court in that case found the United States District Court's reasoning on the issue before it to be persuasive).

The court in *Emery Resource Holdings* also relied on *Rimledge,* as does EOG. In *Rimledge,* locators of uranium mining claims executed a mining deed reserving "a royalty of fifteen per cent (15%) of all gross proceeds from the sale of ore from said claims." Sales of raw unconcentrated ore from the mine began in 1955. Two years later, a third party completed a mill at which the ore could be processed into concentrated ore. Under a subsequent arrangement to sell milled concentrated ore, the operator continued to pay royalty based on the price of unconcentrated ore. The royalty owners demanded royalty on the concentrated ore price without deduction for milling costs. The Utah Supreme Court held that the parties intended the base for

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[57] *See also White-Rodgers Co. v. District Court,* 160 Colo. 491, 418 P.2d 527 (1996); *First National Bank v. Rostek,* 182 Colo. 437, 442 n. 1 (1973).

royalty payments to be the proceeds realized from the sale of raw ore, particularly in light of the fact that there was no mill available when mining and sales began. 13 Utah 2d at 333-334. The court went on to add a statement that "whether the words employed to designate the royalty basis are 'market value,' 'proceeds,' or 'gross proceeds,' they do not mean, under normal circumstances that the value added to the product shall redound to the benefit of a royalty owner who does not bear his proportionate share of the costs." 13 Utah 2d at 334; 374 P.2d at 23 (footnotes omitted). The court cited cases from other states involving, variously, gas treatment, gas transportation, gas processing, and crude oil dehydration.

The *Rimledge* court's statement is no more than *dictum* for several reasons. First, *Rimledge* did not involve oil and gas. Second, there was no suggestion that the mining deed involved in that case implied a covenant to market for the mutual benefit of the transferor and the transferee analogous to the implied covenant involved in an oil and gas lease. *Rimledge* did not involve any question of whether a lessee who is subject to an implied covenant to market must put production into marketable condition without the lessor sharing in those costs. Third, there was no suggestion that uranium ore must be milled to concentrated form before it is marketable.[58] In short, *Rimledge* is inapposite here.

2. Gas of "Like Grade and Quality"

As quoted above, the language in the royalty clause in the subject leases that follows the value at the well provision establishes an approved contract price as the measure of value and establishes the floor as "the price for gas . . . received by the United States of America for its royalties from gas of like grade and quality from the same field." EOG argues that "[t]he modifier of 'like grade or quality' provides for netting-back to the value 'at the well.'" EOG Response Brief at 4. This argument is illogical and takes the language out of context. The reference to "like grade and quality from the same field" refers to the physical characteristics of the gas.[59] It has nothing to do with the allocation of costs of treatment or sharing of costs between the lessor and the lessee.

3. The Utah Supreme Court's 2003 Decision in *ExxonMobil Corp. v. Utah State Tax Commission*

EOG further relies on the decision of the Utah Supreme Court in *ExxonMobil Corp. v. Utah State Tax Commission*, 2003 UT 53, 86 P.3d 706 (2003), *modified on other grounds*, *Union Oil Co. of California v. Utah State Tax Commission*, 2009 UT 78, 222 P.3d 1158 (2009). *ExxonMobil* involved a claim for refund of allegedly excess severance taxes paid on crude oil produced from numerous wells in southeastern Utah. This was not a royalty case, and the opinion never mentioned the terms of state oil and gas lease instruments.

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[58] Analogously, crude oil is marketed worldwide before it is refined. It does not need to be refined to be marketable.

[59] "Quality" is the term most used with respect to the physical characteristics of natural gas. While the term "grade" may be used occasionally, "grade" usually is used in reference to crude oil.

Under the severance tax provisions in force at the time of the *ExxonMobil* case, a four percent severance tax was imposed on "the value, at the well, of the oil or gas produced, saved, and sold or transported from the field where the substance was produced." Utah Code Ann. § 59-5-102(1)(a) (2000). The statute specifically defined "value at the well" as "the value of oil or gas at the point production is completed." Utah Code Ann. § 59-5-101(19) (2000). The Utah Supreme Court held that "to qualify as the point at which production is complete, that point must be one at which sales of the oil and gas may actually occur." 2003 UT 53, & 19, 86 P.3d at 711. Though valuation "is to occur in the immediate vicinity of the point of removal, it need not necessarily occur at the point of physical removal from the earth. There appears to be a market for oil and gas taken from the separator tanks near the well head." *Id*. at & 21.[60]

EOG argues that the phrase "value at the well" has the same meaning for all purposes under Utah law as that applied by the State Supreme Court on *ExxonMobil*. EOG Response Brief, pp. 7-8. EOG's inductive leap is illogical. In *ExxonMobil*, the severance tax statute contained a specific definition of the phrase "value at the well." That statutory definition, by its terms, applies only to severance taxes and does not govern the terms of mineral leases, whether State or private. EOG's oil and gas leases do not contain such a definition.

Moreover, in 1953, at the time the first four of the seven EOG leases involved in this appeal were issued, the severance tax on oil and gas did not exist in its current form. Until 1988, severance taxes for oil and gas were combined with taxes on metal mining into one tax. In 1953, the rate was 1 percent of "net proceeds," which was defined as gross proceeds less certain deductions—for example, transportation and smelting costs. Separate oil and gas severance taxes were established in 1988.[61] Obviously, the statute does not operate to define terms used in oil and gas leases issued decades before the statute was enacted.

Nor is it logical to argue that a definition included in a severance tax statute operates to define terms in State oil and gas leases issued after the statute was enacted that do not refer to or incorporate that definition. For all of these reasons, EOG's reliance on *ExxonMobil* is misplaced.

In summary, EOG's arguments for why the Utah Supreme Court would adopt the apparent majority approach are not persuasive.

B. SITLA's Arguments

[60] The oil and gas severance tax statute at Utah Code Ann. §§ 59-5-101 *et seq.* subsequently has been substantially amended and no longer includes the terms and phrases quoted. Without going into details not relevant here, it suffices to say that in substantive effect, the current statute codifies the Utah Supreme Court's approach in *ExxonMobil*.

[61] *See* Utah State Tax Commission, *History of the Utah Tax Structure* (June 2011), pp. 235-239, available at: https://www.yumpu.com/en/document/view/18221186/history-of-utah-tax-structure-utah-state-tax-commission-utahgov.

SITLA, for its part, argues that the Board should adopt the apparent minority view of the courts in other states, on the ground that the language of the royalty provision "does not allocate marketable condition costs, and the implied covenant to market requires they be borne by the lessee." SITLA Opening Brief, p. 25. SITLA maintains that "among the blanket rule approaches, this is the better reasoned," pointing specifically to the Supreme Court of Colorado's decision in *Rogers v. Westerman Farm Co.*, 29 P.3d 887 (Colo. 2001). *Id*.; *see also* SITLA Reply Brief, pp. 10-11.

SITLA advances three other arguments for the proposition that costs to put production into marketable condition are non-deductible under the subject leases, two of which are grounded in the language of the leases. Preliminarily, the Board notes that during oral argument, SITLA downplayed or minimized its reliance on these theories, describing them as only "alternative" arguments if the Board rejects SITLA's position regarding the Federal floor proviso. SITLA emphasized that its principal reliance and focus was on the Federal floor proviso. Consequently, the Board can address these arguments more summarily than perhaps otherwise would be appropriate.

1. Lease Instrument Language Expressly Providing for Deductions Only for Processing Costs

SITLA first argues that the language of the lease instrument expressly provides only for deduction of processing costs and for no other cost deductions. SITLA Opening Brief, pp. 6-7 and 19-20; SITLA Reply Brief, p. 9. Therefore, SITLA argues, costs of treating production to make it marketable are not deductible. This theory implies, as SITLA acknowledges, that if the sale occurs downstream after the gas is transported to a distant market (Salt Lake City, for example), EOG would have to bear all costs of transportation as well as treatment, and the State as lessor would bear no share of the costsCexcept for its share of processing costs, which are expressly deductible under the lease instrument. The lessor would not share in any costs incurred after the point of extraction unless expressly provided for in the lease.

With respect to the meaning of the implied covenant to market, at least under a "value at the well" royalty clause, this argument simply begs the question. Courts that have adopted the apparent majority rule would simply respond that the "at the well" language itself provides that all costs incurred subsequent to physical severance are deductible.

Even under the apparent minority line of cases, SITLA's argument is a novel proposition that is unsupported in the case precedents. Lease instruments providing for royalty as a percentage of the value of production (whether "at the well" or not), or as a percentage of proceeds derived from the sale of production, and which are silent with respect to the costs of transporting production to distant downstream markets, consistently have been construed to require the lessor to bear its proportionate share of costs of transporting production to downstream markets distant from the lease once a marketable product is obtained (*i.e.*, the production is in marketable condition).[62]

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[62] *See, e.g.*, *Rogers v. Westerman Farm Co.*, *supra*, 29 P.3d at 900 (Colo. 2001); *Mittelstaedt v. Santa Fe Minerals, Inc.*, 954 P.2d 1203, at 1205-1208 (Okla. 1998); *Johnson v. Jernigan*,

In the context of Federal leases, transportation costs were allowed as deductions for more than 40 years before the specific transportation allowance rules at 30 C.F.R. §§ 206.156-206.157 (1988-2010) and 30 C.F.R. §§ 1206.156-1206.157 (2011-2020) were adopted. *See* 53 Fed. Reg. 1230, 1257 (Jan. 15, 1988); *United States v. General Petroleum Co*., 73 F. Supp. 225, 263 (S.D. Cal. 1946), *affirmed*, *Continental Oil Co. v. United States*, 184 F.2d 802, 818-820 (9th Cir. 1950); *Shell Oil Co.*, 70 I.D. 393, 395 (1963); *Kerr-McGee Corp.*, 22 IBLA 124, 127-127 (1975).

Thus, the absence of specific language in the lease instrument regarding deductibility of costs does not imply that the lessee must bear all costs incurred for all functions that are not specifically identified as deductible. The case on which SITLA relies, *Commissioner of the General Land Office of State of Texas v. SandRidge Energy, Inc.*, 454 S.W.3d 603 (Tex. App. 2014) (SITLA Reply Brief, p. 9), does not stand for the proposition for which SITLA cites it. *SandRidge* involved a number of leases with several different royalty clauses, some of which were Texas state leases. The court construed the royalty provision in the state leases as a "value at the well" provision. With respect to so-called "post-production" costs, the state leases included a "no deductions" clause, under which the lessee agreed that royalties would be computed "without deduction for the cost of producing, gathering, storing, separating, treating, dehydrating, compressing, processing, transporting, and otherwise making the oil, gas and other products hereunder ready for sale or use."

The *SandRidge* court applied the Texas Supreme Court's ruling in *Heritage Resources v. Nationsbank*, 939 S.W.2d 118 (Tex. 1996). In *Heritage Resources*, the leases contained "market value at the well" royalty clauses, with a "no deductions" clause that read: "provided, however, that there shall be no deductions from the value of the Lessor's royalty by reason of any required processing, cost of dehydration, compression, transportation or other matter to market such gas." The Texas Supreme Court held that "the commonly accepted meaning of the 'royalty' and 'market value at the well' terms renders the post-production clause [*i.e.*, the no deductions clause] in each lease surplusage as a matter of law." 939 S.W.2d at 123. The concurring opinion concisely explained the reasoning: "The concept of 'deductions' of marketing costs from the value of the gas is meaningless when gas is valued at the well. Value at the well is already net of reasonable marketing costs." *Id*. at 130 (Owen, J., concurring). The Texas court's approach in *Heritage Resources*, and applied in *SandRidge*, is a hard example of the apparent majority view regarding treatment and other "post-production" costs. *SandRidge* and *Heritage Resources* are examples of the line of cases on which EOG, not SITLA, would rely.

2. Contract Sales Price Provision Contains No Provision for Any Deductions

Second, SITLA argues that the part of the lease royalty clause providing that the sales price under an approved contract is the measure of the reasonable market value does not provide

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475 P.2d 396, 399-400 (Okla. 1970); *Sternberger v. Marathon Oil Co.*, 257 Kan. 315, 894 P.2d 788, 800 (1995); *Ashland Oil Refining Co. v. Staats, Inc.*, 271 F. Supp. 571, 575-576 (D. Kan. 1967). *See also* 3 Kuntz, *Law of Oil and Gas*, § 40.5, at 351 (1989-2001 Supp.); 3A Summers, *Oil and Gas*, § 589, at 115-116 (1970).

for any deductions, and that it mandates use of the sales price as the market value for royalty purposes without deductions. SITLA maintains that "[i]f interpretation of this provision were divorced from the protections of the federal regulations governing deductions . . . the plain meaning of this provision provides for no ability to take deductions at all." SITLA Opening Brief, p. 21. *See also* SITLA Reply Brief, p. 8.

The fact that the royalty clause in the subject leases establishes the price under an approved contract as the measure of "reasonable market value at the well," with no mention of (or restriction on) the location where the sale occurs, carries no implication regarding deductibility of costs to put production into marketable condition. SITLA's theory would imply that if the sale occurs downstream after the gas is transported to a distant market, EOG would have to bear all costs of transportation as well as treatment, and the State as lessor would bear no share of those costs. This is inconsistent with the principle and precedents discussed above. At the same time, this theory also would imply that if the lessee is "smart" enough to sell gas under an arrangement where it passes title to the purchaser as soon as possible after the point of extraction, then the State as lessor effectively would bear the royalty percentage share of the costs of all treatment functions performed after the point of sale, as well as the costs of transportation. That is because the sale price used as royalty value would be reduced because the purchaser would have to bear those costs. Under this theory, therefore, the lessee's and the lessor's respective rights and obligations with respect to "post-production" costs would depend on the location of sale; the lessor effectively would share in costs incurred after the point of sale but would not share in costs incurred before the point of sale. Neither precedent nor logic supports this notion.

SITLA cites *Chesapeake Exploration, L.L.C. v. Hyder*, 483 S.W.3d 870 (Tex. 2016), for the proposition that no costs incurred before the point of sale are deductible when royalty is based on the proceeds received under an approved contract. *Hyder* does not stand for that proposition. The lease at issue in *Hyder* provided for a "cost-free" so-called "overriding royalty" of 5 percent of gross production obtained from directional wells drilled on the lease but bottomed on adjacent land outside the lease. 483 S.W.3d at 872. Stated differently, the lessors obtained from the lessee what was in substance a fee for producing gas from property outside the lease, in which the lessor had no property interest (and, therefore, no royalty interest). That fee was expressed in terms of a percentage of the gas produced from the adjacent property.

Chesapeake paid the lessors their "overriding royalty" on the basis of 5 percent of the price Chesapeake's affiliate paid to Chesapeake, before the affiliate gathered and transported the gas and sold it at arm's-length in distant markets. The affiliate paid Chesapeake a price calculated based on a weighted average of the arm's-length sales prices the affiliate received, minus "postproduction costs" for gathering, transportation, and a 3 percent "marketing fee." The lessors argued that the so-called "overriding royalty" should have been paid on the affiliate's sales price received in the arm's-length sales to third parties.

The Texas Supreme Court noted that an overriding royalty (under Texas precedents), "is like a landowner's royalty in that it usually bears postproduction costs but not production costs, though the parties may agree to a different arrangement." 483 S.W.3d at 873. The court held that under the circumstances of that lease, the parties did agree to a different arrangement and that the term "'cost-free' in the overriding royalty provision includes postproduction costs." *Id*. at 875.

This does not support SITLA's argument that no costs incurred before the point of sale are deductible when royalty is based on the proceeds received under an approved contract, and when the lease does not expressly provide that particular costs are not deductible.[63] Neither courts nor this Board can make a better contract for SITLA than it has made for itself. *E.g.*, *Bakowski v. Mountain States Steel*, 2002 UT 62 ¶ 19, 52 P.3d 1179, 1185 (2002); *Load Zone Management, LLC v. Clark*, 333 P.3d 1255, 1260 (Utah Ct. App. 2014).

3. SITLA's Administration of a Trust for the Benefit of the Public

SITLA further maintains that because it administers a trust for the benefit of the public, "the Board should consider the existence of the Trust and the statutory requirement to obtain the optimum values for the beneficiaries as a surrounding circumstance informing the intent of the parties at the time the lease was signed." SITLA Opening Brief, pp. 27-28. SITLA argues that EOG's interpretation of the value at the well provision conflicts with these mandates. *Id*. SITLA's argument seems to suggest that in the event of any disagreement as to the meaning of any term of the lease, the intent of the lease should be read in SITLA's favor because it administers the lands for the benefit of the school system.

The law does not give SITLA such an extra "thumb on the scales" in legal disagreements with its lessees. The Utah Supreme Court observed in *State v. Mathis*, 223 P.3d 1119 (Utah 2009), that "the constitutional appointment of the State as trustee over the school trust lands does no more than impose on the State the ordinary authority and obligations of a trustee." *Id.* at 1124, & 26. Though the issue in that case is not relevant here, the court's statement reflects the principle applicable here. It is up to SITLA to ensure that it acts as a trustee in the best interest of the school system when it enters into leases for the development of school trust-owned mineral resources. If it fails to do so, then the State as a trusteeCnot an outside partyChas the obligation "to make the beneficiary whole when the trust has suffered a loss resulting from the trustee's mismanagement." *Id*. at 1122, & 15. As concerning the lessee's obligations, the lease instruments involved in this appeal must be interpreted according to established principles.

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[63] EOG argues that *Hyder* should be distinguished because the gas royalty clause of the lease in *Hyder* expressly stated that the royalty was free and clear of all production and post-production costs and expenses, including gathering, separating, dehydrating, compressing, transporting, processing, and treating the gas incurred between the wellhead and the point of delivery or sale. EOG Response Brief, p. 11. However, the gas royalty clause which EOG quotes was not at issue in the appeal. In *dicta* the *Hyder* court took the view that the additional free-and-clear-of-costs-and-expenses language "has no effect on the meaning of the provision. It might be regarded as emphasizing the cost-free nature of the gas royalty, or as surplusage." 483 S.W.3d at 873. The *Hyder* court adhered to the general Texas rule that the lessor under leases with a "value at the well" royalty clause shares in "postproduction" costs, discussing *Heritage Resources, Inc. v. NationsBank*, *supra*, and citing other cases.

In summary, the arguments of both EOG and SITLA regarding the phrasing of the lease instruments and the implications of existing Utah Supreme Court and U.S. District Court precedents are unpersuasive. Thus, they do not adequately inform the question of whether the Utah Supreme Court would adopt the view of the apparent majority of the states or the apparent minority of the states regarding the scope and implications of the lessee's implied covenant to market for the mutual benefit of the lessee and the lessor and its application under a "value at the well" royalty provision.

C. Majority versus Minority Lines of Cases

It is not necessary here to discuss these two general lines of cases at length. It suffices here to summarize the fundamental positions of each. The apparent majority view is that (1) the implied covenant to market for the mutual benefit of the lessee and the lessor has no implication with respect to the physical condition of the production, and (2) a value "at the well" clause means value is to be determined at a location where production is complete that is upstream of the locations where any of the functions are performed to treat the gas to put it into marketable condition, to process the gas, or to transport it for sale at a market away from the lease or unit. In other words, a "value at the well" clause allocates costs incurred after the point of extraction. Under this view, if the gas is not sold "raw" and the starting point for determining royalty is a downstream sales price, all the costs incurred in functions performed downstream of the immediate vicinity of the well should be deducted in determining royalty value.

The apparent minority of courts take the view that (1) the "at the well" valuation phrasing is silent as to allocation of costs, and (2) the implied covenant to market includes the obligation to make the gas marketable from the standpoint of its physical composition and condition (and, in at least one state, the location of the market).

Two of the apparent minority line of cases from Colorado also advance a rationale related to the basic relationship of the lessee and the lessor. *Garman v. Conoco, Inc.*, 886 P.2d 652 (Colo. 1994), involved a 4 percent overriding royalty interest reserved in the transfers of the leases to Conoco. The overriding royalty provision was silent with respect to allocation of "post-production" costs. However, like a reserved royalty in the original lease, an overriding royalty is free of the costs of production, and the court addressed the issue as a matter of general principles of oil and gas law relating to the allocation of post-production costs and as a statement of the general principles of Colorado law.

In *Garman*, the gas passed through a gathering line, in the process of which it was compressed and dehydrated, to a processing plant located outside both the lease and the unit boundaries, where NGLs were extracted. The overriding royalty owners conceded that both transportation from the processing plant and the costs of processing to extract the NGLs were properly deductible; they objected to deducting gathering, compression, and dehydration costs.

In holding that these costs were not deductible, the Colorado Supreme Court first observed that "[i]mplied lease covenants related to operations typically impose a duty on the oil and gas lessee[,]" citing 5 Kuntz, *A Treatise on the Law of Oil and Gas*, §§ 57.1 to 62.5 (1989). 886 P.2d at 660. "Accordingly the lessee bears the costs of ensuring compliance with these promises." *Id*. The court further observed that it would conflict with the purpose of an oil and gas lease if the implied covenant to drill, for example, obligated the lessor to pay for his proportionate share of drilling costs. *Id*.

The *Garman* court further said that allocating marketable condition costs to the lessee "is also traceable to the basic difference between cost bearing interests and royalty and overriding royalty interest owners." *Id*. The court explained that non-operating working interest owners (*i.e.*, co-lessees) have the right to discuss procedures and expenditures "and ultimately have the right to disagree with the course of conduct selected by the operator. . . . This right checks an operator's unbridled ability to incur costs without full consideration of their economic effect. No such right exists for nonworking interest owners" (*i.e.*, lessors/royalty interest owners). *Id*.

In a later case, the Colorado Supreme Court addressed the deductibility of costs of gathering, compression, and dehydration before gas entered an interstate pipeline in the context of leases with royalty clauses based on the gas "at the well" or "at the mouth of the well," including market value at the well or market price at the well clauses.[64] *Rogers v. Westerman Farm Co.*, 29 P.3d 887 (Colo. 2001) (cited in SITLA Reply Brief, p. 10, as noted above). The court in *Rogers* followed its decision in *Garman* and held the costs to be non-deductible.

The arguments underlying both the apparent majority and apparent minority lines of cases are reasonable and carry weight, and the Utah Supreme Court could go either way. It appears accurate to say that neither set of arguments is truly compelling.

The courts in the apparent majority line of cases do not appear to have adequately or persuasively addressed the two considerations raised in the *Garman* opinion, as quoted above, which was followed and applied in *Rogers*. In the Board's view, it is not clear why the implied covenant to market should be treated differently from other implied covenants that impose a duty on the lessee, in terms of who bears the costs to fulfill the duty. Further, non-working interest owners such as royalty owners do not possess any check on the operator's ability to incur costs without full consideration of their effect.

For these reasons, in the Board's opinion, the apparent minority view is more persuasive. The Board therefore believes that the better reading of the phrase "market value at the well" is that it does not allocate costs incurred after physical severance occurs, and that the implied covenant to market production should be held to obligate the lessee to perform at its own expense those functions which, under the circumstances, are necessary to make gas marketable. In any event, however, the Federal floor proviso controls.

III. <u>Gas Used as Fuel in Treatment, Processing, and Transportation</u>

[64] The pressure at the wells ranged from 15 - 250 psig. The produced gas stream contained about 40 pounds of water per million cubic feet. To meet the interstate pipeline specifications, the gas was gathered from various wells through a set of low pressure lines and moved to the main line. The gas was then compressed to a higher pressure and dehydrated to meet the pipeline specifications. Acid gas removal and processing were not involved because the particular gas was free of H_2S and CO_2 and NGLs.

Before applying the principles explained in Part I of this analysis to the Findings of Fact to determine when, or at what point, EOG's gas is in marketable condition, and what costs are deductible in calculating royalty value, it is necessary to address the royalty implications of gas used as fuel in gathering, dehydration, compression, desulphurization, processing, and transportation operations. Issue 4 in the 2018 Audit Report is identified as "Fuel Charges." The report states:

> After gas is processed through the Ironhorse/Stagecoach plant, residue gas is sent through Questar pipeline to be sold downstream. Gross proceeds are determined by the gas volume delivered, not receipted into the pipeline. The difference between receipt and delivered is fuel used along the pipeline, but since EOG does not use the receipt volume when determining gross sales it cannot convert fuel use into a transportation deduction. Doing so results in EOG taking this allowance twice.
>
> EOG, in its gross up methodology to account for gas taken in kind, converts fuel used in the field into a transportation allowance. The problem with this is two-fold. First this is a marketable condition cost and second, since EOG's royalty measurement point is the tailgate of the plant, fuel used before that point would be considered gathering. This would also be the case for any other fuel used in the field like gas lift injection.

2018 Audit Report, p. 4. This raises two issues, namely, the proper treatment for royalty purposes of (1) gas used as fuel for compressors in the course of transportation; and (2) gas used as fuel to power compressors, dehydrators, desulphurization equipment and gathering equipment, or as fuel to power the processing plants, before the inlet to the Questar pipeline. The parties' briefs indicate that they now agree as to the underlying legal principle that applies in each of these respective circumstances (although not necessarily for the same reasons). The applicable legal principles may be summarized as follows:

1. Residue gas used as fuel in facilities, such as compressors, along the Questar pipeline downstream of the inlet to that line is a part of the transportation cost EOG incurs. Because these volumes are part of the volumes removed from the lease or unit, they are royalty-bearing (for the reasons discussed below) and therefore must be included in the total volume on which royalty is owed and calculated. At the same time, however, the value of the volumes used as fuel is a cost of transportation and may be deducted in calculating the value of the total royalty-bearing volume. The deducted amount counts toward the 50 percent cap on allowable transportation costs.

If further examination reveals that EOG did not include the volumes used as fuel in the Questar pipeline compressors when it reported the royalty-bearing volume, royalty volumes and transportation allowances must be corrected accordingly. EOG may not both disregard the fuel-use volumes in reporting the volume on which royalty is due and at the same time subtract transportation costs paid in cash in calculating the royalty value of volumes delivered to purchasers up to a level of 50 percent of the value of the delivered volumes. The sum of transportation costs paid in cash and the value of volumes used as fuel along the pipeline may not exceed 50 percent of the value of the total of the royalty-bearing volumes—*i.e.*, the delivered volumes plus the fuel-use volumes.

2. Gas used as fuel in operations performed on the lease or unit from which the gas is produced is not royalty-bearing because these volumes do not leave the lease or unit. As quoted in Part I of this analysis above, the lease terms of all the leases involved in this appeal impose royalty on the value of "gas produced <u>and saved or sold from the leased premises</u>." (Emphasis added.) For the reasons explained above, unitization modifies this provision for unitized leases to apply to gas produced and saved or sold from the unit. Gas that is consumed as fuel in operations conducted on the lease or unit from which the gas is produced is not saved or sold from the lease or unit, and therefore is not royalty-bearing. That is true regardless of the function in which the gas is used as fuel, and even if the gas is used in operations the cost of which otherwise would not be deductible (*e.g.*, functions necessary to put the gas into marketable condition).

This is the same principle that applies to gas produced from Federal leases under the terms of the MLA at 30 U.S.C. ' 226(b)(1)(A) and (c)(1) and standard Federal lease terms, under which royalty is a specified percentage of the "value of the production removed or sold from the lease." *See* the discussion in *Plains Exploration & Production Co*., 178 IBLA 327, 332-337 (2010), which EOG cites in its Petition for Review (p. 12). The same principle applies in the case of both Federal and state leases because the relevant lease terms are functionally identical. It is not a consequence of the Federal floor proviso in the state leases. The Federal floor proviso requires that the value of production be not less than the value calculated under the Federal royalty valuation rules, not that the royalty-bearing volume be not less than the volume that is royalty-bearing under Federal lease terms or regulations. The lease terms of the state leasesCnot the Federal floor provisoCdefine what production is royalty-bearing.

3. However, under the circumstances of the present case, one difference between Federal and state leases regarding treatment of gas used as fuel in processing plants does arise. MMS/ONRR regulations in force throughout the relevant period provide that "[a] reasonable amount of residue gas shall be allowed royalty free for operation of the processing plant . . . ." 30 C.F.R. § 1202.151(b) (2011-present); former 30 C.F.R. § 202.151(b) (1988-2010). This provision applies to Federal oil and gas leases. It allows royalty-free use of a reasonable amount of residue gas for operation of the processing plant. It is not limited to gas produced from the lease or unit on which the processing plant is located. It applies equally to gas used as fuel in processing plants located off the lease or unit.

This provision applies to calculating the volume of gas on which royalty is due under Federal leases, not the value of the gas on which royalty is computed. Title 30 C.F.R. part 1202 (and former 30 C.F.R. part 202) are not part of the Federal royalty valuation rules. Thus, the Federal floor provisoCwhich operates to require that the royalty value of gas produced from or allocated to state leases be not less than the value of gas produced from or allocated to Federal leases in the same fieldCdoes not operate to make this regulation applicable to state leases.

Neither the terms of the state leases nor applicable state statutes or regulations contain an analogous provision for royalty-free use of gas as fuel in operating a processing plant located off the lease or unit from which the gas is produced. Thus, under the subject leases, the value of gas used as fuel in processing plants located off the lease or unit is part of the costs of processing.

The Federal processing allowance rules[65] implement the same concept as the processing allowance provisions in the royalty clauses of the state lease instruments quoted at the beginning of Part I of this analysis. The Federal floor proviso makes these rules applicable to calculating the minimum royalty value under the state leases at issue here. That includes the requirement that processing allowances may not exceed two-thirds of the value of the extracted products absent approval by the lessor.

IV. When Is EOG's Gas in Marketable Condition?

Inasmuch as the Federal floor proviso—and, in the Board's view, the implied covenant to market—requires EOG to treat the gas produced from the subject leases so as to put it in marketable condition without deducting the costs of those functions in computing royalty value, the question then is at what point the gas is in marketable condition under the facts set forth in the Findings of Fact.

As explained in Part I.B. of this analysis above, gas must be in a condition in which it is "sufficiently free from impurities and otherwise in a condition that [it] will be accepted by a purchaser under a sales contract typical for the field or area" (30 C.F.R. § 1206.151 (2011-2020); former 30 C.F.R. § 206.151 (1988-2010)). All the gas at issue in this appeal was sold as processed residue gas in distant markets far downstream of the leases and units, and those contracts were for treated gas. The established demand for an identified product was for treated gas. Moreover, and as the numerous precedents cited in Part I.B. require, the lessee must gather the gas from the wells and treat the gas to ensure that it meets specifications for pressure, water content, and acid gas content to be accepted into the transportation pipeline.

A. Gathering

As quoted above, 30 C.F.R. § 1206.151 (2011-2020) and former 30 C.F.R. § 206.151 (1988-2010) define "gathering" as follows:

> *Gathering* means the movement of lease production to a <u>central accumulation and/or treatment point on the lease, unit</u> or communitized area, or to a central accumulation or treatment point off the lease, unit or communitized area as approved by BLM . . . for onshore . . . leases . . . . [Emphasis added.][66]

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[65] 30 C.F.R. §§ 1206.158-1206.159 (2011-2020), formerly 30 C.F.R. §§ 206.158-206.159 (1988-2010).

[66] The new rule effective February 16, 2021, continues this definition for onshore Federal leases. 30 C.F.R. § 1206.20 (2021).

The 1988 rule's definition modified the concept of "field" gathering established under earlier case precedents in some circumstances. For example, there may be more than one BLM-approved accumulation point in what otherwise would constitute a "field." In such a circumstance, transportation may begin sooner than under the earlier concept of "field" gathering. In another situation, in contrast, BLM may have approved an accumulation or treatment point off the lease or unit, and that point is outside the field. In such a circumstance, transportation may begin later than under the earlier precedents.

Further, as quoted previously, the transportation allowance regulations at 30 C.F.R. § 1206.156(a) (2011-2020), formerly 30 C.F.R. § 206.156(a) (1988-2010), provide in relevant part:

> Where the value of gas has been determined pursuant to . . . § 1206.153 of this subpart [*i.e.*, for processed gas] at a point (e.g., sales point . . .) off the lease, ONRR shall allow a deduction for the reasonable actual costs incurred by the lessee to transport . . . residue gas, and gas plant products <u>from a lease to a point off the lease</u> including, if appropriate, transportation from the lease to a gas processing plant off the lease and from the plant to a point away from the plant. [Emphasis added.]

Stated differently, the costs of moving gas from one facility to another facility within the boundaries of the leaseCor unit, if the lease is part of a unitCmay not be deducted as part of a transportation allowance.

1. Production from or Allocated to ML 3077, 3078, and 3355 in the Chapita Wells Unit

In the instant appeal, all measurement, dehydration, desulphurization, and compression of gas produced from or allocated to ML 3077, ML 3078, and ML 3355 in the Chapita Wells Unit occurs within the boundaries of the unit. As explained above, the effect of unitization is to combine all production from a participating area within the unit and allocate that production to all leases within the participating area. The combined allocation of production from the respective participating areas allocates the entire production from all leases within the unit. The unit supersedes the individual lease for purposes of determining the royalty obligations and royalty owed on unitized production.

All movement of this production from the wells through the outlet of the Coyote compressor station (the first point through which all gas produced from wells on the unit passed) was on the unit. This movement therefore was gathering. Further, for the gas that was then processed at the Iron Horse, Stagecoach, or Chipeta plants and then moved to the Fidlar compressor station and the Questar pipeline inlet, movement through these facilities was for treatment and processing functions performed on the unit. Therefore, the costs of that movement are not deductible in determining royalty value.

However, movement of production from the Coyote compressor station to the Red Wash processing plant (which occurred principally during the first portion of the relevant period before the Stagecoach plant began operation in September 2008) removed the gas from the unit and from the Natural Buttes Field. Movement of production from the Coyote compressor station to the Red Wash plant, and movement of residue gas downstream of the Red Wash plant, therefore was transportation, the costs of which are deductible in determining royalty value.

The fact that processed residue gas was then moved from the Red Wash plant back to the Fidlar compressor station and the inlet to the Questar pipeline, both of which are located on the Chapita Wells Unit, does not imply that movement from the Red Wash plant to the Questar pipeline inlet is not transportation. Had the inlet to the Questar pipeline been at some other location downstream of the Red Wash plant not within the Chapita Wells Unit, that movement clearly would have constituted transportation. In summary, once the gas left the Coyote compressor station to move to the processing plant off the unit and outside the field, subsequent movement constitutes transportation.

This does not imply that all functions performed downstream of the Coyote compressor station for gas moved to the Red Wash plant were transportation functions. Processing took place at the Red Wash plant. Additional treatment functions, such as dehydration or compression (including boosting residue gas), necessary to put the gas into marketable condition may have been performed at the Red Wash plant or at the Fidlar compressor station.

2. Production Allocated to ML 1299 in the Stagecoach Unit

As noted previously, the production allocated to ML 1299 in the Stagecoach Unit was measured at FMPs located at the wells on the unit. The gas also was initially dehydrated and, as necessary, desulphurized, at the well. The gas then moved off the unit to either the Chapita compressor station and from there to the Coyote compressor station, or directly to the Coyote compressor station. From the Coyote compressor station, the gas went to the Iron Horse, Stagecoach, or Chipeta processing plant, as applicable, or to the Red Wash plant early in the relevant period.

An FMP located at each well is not a central accumulation point on the lease or unit. Dehydration (or desulphurization) equipment located at each well also is not a central treatment point on the lease or unit. There was no central accumulation or treatment point on the Stagecoach Unit. The central accumulation or treatment point off the lease or unit was the Coyote compressor station; all the gas allocated to ML 1299 ultimately accumulated there and was compressed at that location. Thus, movement of gas allocated to ML 1299 upstream of the Coyote compressor station is gathering. Movement of that gas beyond the Coyote compressor station to any of the processing plants (all of which are outside the Stagecoach Unit) and further downstream from the plants constitutes transportation under 30 C.F.R. §§ 1206.151 and 1206.156(a) and the former 30 C.F.R. §§ 206.151 and 206.156(a), quoted above. The costs of moving the gas through the line downstream of the Coyote compressor station therefore are deductible.

3. Production from ML 47045

Before completion of the ECW Section 16 Central Facility in 2013, gas produced from wells on stand-alone ML 47045, which adjoins the southeastern portion of the Chapita Wells Unit on the north, was measured at FMPs at the well. That gas also was initially dehydrated and, as necessary, desulphurized at the well. The gas then moved off the lease to the Chapita compressor station, and from there to the Coyote compressor station, or directly to the Coyote compressor station. Gas produced from wells on ML 47045 ultimately accumulated and was compressed at the Coyote compressor station off the lease during this period. Movement of this gas upstream of the Coyote compressor station during this period therefore was gathering. Movement of this gas beyond the Coyote compressor station to any of the processing plants, all of which are off the lease, and further downstream from the plants constitutes transportation under 30 C.F.R. §§ 1206.151 and 1206.156(a) and the former 30 C.F.R. §§ 206.151 and 206.156(a), quoted above.

After the ECW Section 16 Central Facility, located on the lease, began operation in 2013, production from wells on ML 47045 was accumulated and measured and dehydrated at that facility. The ECW Section 16 Central Facility became the central accumulation and initial treatment point on the lease. Movement from the wells to that facility constitutes gathering. Under the cited regulations, after the ECW Section 16 Central Facility began operation, movement of the gas from that facility to the off-lease compression and processing facilities and points further downstream constitutes transportation, the costs of which are deductible.[67]

4. Production from ML 45681

As explained above, production from the one well on non-unitized ML 45681, which consists of the two non-contiguous parcels situated immediately north of the Stagecoach Unit, was measured at an off-lease FMP at the entrance to the Lateral 0 line because ML 45681 is located in a flood plain. Gas produced from ML 45681 then flowed to the Coyote compressor station.

Because there is only one well on ML 45681, no accumulation of gas produced from multiple wells on the lease was necessary. Dehydration and, if necessary, desulphurization would have been performed at the FMP. Movement of this gas to the FMP would not be deductible as a transportation cost. Movement downstream of the FMP to the compressor station(s) and the processing plant(s) and the Questar pipeline constitutes transportation, and the associated line costs would be deductible.

5. Production from ML 48380

There is only one producing well on non-unitized ML 48380, and its production is measured on the lease. That gas then moves directly to the West Desert Tap of the Questar

[67] As noted previously, this does not transform the costs of compression and other treatment functions necessary to put gas into marketable condition performed at the compressor stations and processing plants into transportation costs.

pipeline off the lease. No gathering functions are involved, and all movement of this gas after the FMP constitutes transportation.

B. Compression

In the circumstances of this appeal, there was no market at the lease or unit for uncompressed gas. EOG has not suggested that the gas can be marketed at the pressure at which it comes from the wells.[68] When, as in this case, the market is not in the field, the requisite pressure for the gas to be marketable is the pressure necessary for the gas to enter and pass through the line through which it must pass to be delivered to the purchaser(s). The gas for which there was a market was gas that could be delivered to the purchasers and that the purchasers would accept, *i.e.*, gas at the required pressure, water content, and acid gas content levels for the receiving pipeline. That is the pressure that would enable the gas to be "accepted by a purchaser under a sales contract typical for the field or area," in the words of the definition at 30 C.F.R. § 1206.151. In other words, to meet the requirements of the "sales contract[s] typical for the field or area," EOG had to compress the gas to pipeline pressure.

From the earliest precedents, continuing through the 1988 rules and decisions cited in Part I.B. of this analysis above, the principle that the lessee must compress the gas to a pressure sufficient to enter the relevant pipeline has been uniformly upheld. Where, and in how many phases or steps, EOG chooses to compress the gas to the necessary pressure is up to EOG. But regardless of the physical processes or particular engineering scheme it finds to be most suitable, the costs of compression to the relevant pipeline pressure are not deductible.

As discussed above, the 1988 MMS rules also continued the provision for processed gas that prohibits deducting the costs of boosting (compressing) residue gas after processing. This continued without change when the rules were recodified in 2010. 30 C.F.R. § 1202.151(b) (2011-present); former 30 C.F.R. § 202.151(b) (1988-2010).

As stated in the Findings of Fact above, the pressure required to enter the Questar pipeline at the outlet of the Fidlar compressor station was a minimum of approximately 950 psig, with a maximum of 1,440 psig. In the case of all the gas produced from or allocated to the subject leases in the Chapita Wells and Stagecoach Units, or produced from the adjacent non-unitized leases ML 47045 and ML 45681, compression at the Chapita and Coyote compressor stations—or at the Coyote compressor station for gas that did not go through the Chapita compressor—was necessary to attain that pressure.

As noted in the Findings of Fact, the discharge pressure of one of the two compressor units at the Coyote compressor station that was fed by the Chapita compressor was approximately 960 psigCalmost exactly the minimum pressure necessary to enter the Questar pipeline. However, the discharge pressure of the other unit fed by the Chapita compressor, and the discharge pressure from the other seven units at the Coyote station (which took gas directly

[68] The sole exception is the gas produced from ML 48380 in the Uteland Butte Field, which flows directly into the Questar pipeline (many miles downstream of the Fidlar compressor station) without compression. No compression costs were incurred for that gas.

from producing wells through all stages of compression) was approximately 1,100 psig. That pressure is significantly higher than the pressure necessary to enter the Questar pipeline, and, therefore, higher than the pressure necessary to put the gas into marketable condition. Consequently, under ONRR's allowed methodology for allocating between treatment and transportation functions costs paid as so-called "bundled" fees under contracts for gathering and compression services, a small portion of the costs attributable to the Coyote compressor station may be deductible in calculating royalty value under the Federal floor proviso. That question is addressed in Part V of this analysis below.

The fact that compression was performed at locations off the Stagecoach Unit for ML 1299, and off the lease for ML 47045 and ML 45681, does not affect the principle that costs of compression necessary to meet pipeline pressure requirements are not deductible. The lessee is required to put production into marketable condition without deducting the associated costs, regardless of whether the treatment functions are performed on the lease or unit or off the lease or unit.

In addition, the costs of compression of residue gas after processing at any of the processing plants or at the Fidlar compressor station are non-deductible under the regulation cited above.

The portion of gas or, in the case of the Fidlar compressor station, residue gas, produced from or allocated to ML 3077, ML 3078, and ML 3355 in the Chapita Wells Unit that was used as fuel in the Chapita, Coyote, and Fidlar compressor stations is not royalty-bearing because all of those compressors are located on the unit. However, the portion of gas or residue gas used as fuel in any of those compressors that is allocable to ML 1299 in the Stagecoach Unit or to ML 47045 and ML 45681 is royalty-bearing because it was removed from the lease or unit before being consumed as fuel. These volumes must be added to the reported volumes for these leases if EOG did not include them in its original royalty reports.

C. Dehydration

From 2007 until sometime in 2013, in almost all instances, a dehydration unit was located at each well site and dehydration occurred on the respective leases and units before gas entered the gathering system. After the East Chapita Wells (ECW) Section 16 central system was installed in 2013, dehydration for production from the wells on this system, *i.e.*, wells on ML 47045 (APP 000094) occurred at that facility. After the Davies Road central facility was installed in 2014, dehydration for production from the wells on this system, *i.e.*, wells on ML 3355 and on adjacent Federal leases on sections 29, 28, and 33 of T 9 S R 23 E, S.L.M. within the Chapita Wells Unit (APP 000094)) occurred at that facility. Dehydration of gas produced from other wells on the subject leases and units continued to occur at the well sites. Further dehydration was performed at the processing plants.

The maximum water content level for gas to be accepted into the Questar pipeline was 5 pounds of water per million cubic feet. EOG has neither asserted nor suggested that the gas involved in the present case was dehydrated to a level beyond what was necessary to meet pipeline quality specifications for some other purpose. Dehydration to pipeline quality specifications was necessary to put the production into marketable condition. The costs of dehydration therefore are not deductible in determining the minimum value under the Federal floor proviso.

EOG cites *Exxon Corp.*, 118 IBLA 221 (1991), for the proposition that "not all compression, dehydration, or treatment is performed to make gas marketable." EOG Petition, p. 9. *Exxon* involved the unusual situation of the LaBarge Field in Wyoming. The gas stream had unique characteristics that made it especially difficult to handle. The raw gas stream consisted of 65.4 percent CO_2, only 22 percent methane, 7.5 percent nitrogen, 4.5 percent H_2S (an extraordinarily high concentration), and 0.6 percent helium. 118 IBLA at 223. The gas was initially dehydrated at a central facility just outside the producing units to a much drier condition than called for in the sales contracts. It was then transported approximately 40 miles to the Shute Creek gas processing plant, which operated at cryogenic temperatures, where the gas was separated into its components. The H_2S was manufactured into elemental sulfur and sold. The residue methane was sold at the plant tailgate. The separated nitrogen was sold at the plant tailgate, and CO_2 extracted from the raw gas stream also was sold. Thus, separate components of the gas stream became royalty-bearing products, and the cost of their removal therefore properly became the subject of a processing allowance.

The IBLA allowed Exxon to deduct the cost of dehydration in the field facility, which the IBLA called a cost of "transportation." Though the IBLA described it as such, it is clear from the context that this was not a cost of transportation in the sense ordinarily understood. The dehydration was undertaken as part of moving the raw gas stream to the processing plant. Had the plant been built at a central field location (like the initial dehydration facility was), the dehydration performed at the field facility would have been performed at the plant as part of processing the gas, and there would have been no need for the field facility. The IBLA acknowledged as much. 118 IBLA at 241. Therefore, although the IBLA described the dehydration as undertaken for "transportation," it was to facilitate movement to the processing plant and was for purposes of processing the gas. It was a function that ordinarily would have been done at the processing plant and would have been part of the costs taken into account in determining the processing allowance. In a later case, *Nexen Petroleum USA Inc.*, 157 IBLA 286 (2002) (upheld in *Nexen Petroleum U.S.A., Inc. v. Norton*, Civil No. 02-3543 (E.D. La. Mar. 31, 2004)), an offshore gathering case, the IBLA further noted regarding the *Exxon* decision:

> There, the Board permitted Exxon to deduct costs of initial gas dehydration as a "transportation allowance" because dehydration of the "atypical" sour gas stream was necessary for the long trip to the treatment plant to avoid shutdown of the operating system. Without dehydration to a level not required for marketing under the sales contract, excessive water would freeze and shut down the operating plant. Accordingly, dehydration was necessary to transport the gas, not to sell it or put it in marketable condition.[11]
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>
> [11] Indeed, Exxon's gas had to be dehydrated to ".01 lbs. water/mcf * * * as any water would freeze at the -310EF operating

> temperatures and cause the shutdown of the Manufacturing Facility. Exxon=s methane sales contract, by contrast, call[ed] for a maximum of 5 lbs. water/mcfC500 times the amount necessitated by the manufacturing process." 118 IBLA at 235-36 (footnote omitted).

157 IBLA at 299. It is readily apparent from the stipulated facts and the discussion above that this appeal does not present circumstances similar or analogous to the *Exxon* LaBarge case.

Under the principles discussed above, gas used as fuel in dehydration equipment located at the wells or on the lease or unit from which the gas was produced, such as the ECW Section 16 central facility on Lease 47045 or the Davies Road central facility on the Chapita Wells Unit, is not royalty-bearing because it does not leave the lease or unit.

In addition, if the wellhead for the well producing from ML 45681 is located off the lease because the well location is in a flood plain, gas used as fuel in dehydration equipment at the wellhead location also will not be royalty-bearing. Absent the special circumstances involving a flood plain, the wellhead and equipment presumably would have been located on the lease, and dehydrator fuel gas then would not have been royalty-bearing. Approval of an off-lease wellhead location because of these circumstances should not change that principle or result in effectively penalizing the lessee.

D. Desulphurization/Sweetening

As noted in the stipulated facts, gas produced from the subject leases and units was treated as necessary to remove H_2S to meet the quality specifications in EOG's contracts with the gathering system operated by QEP Resources and its Questar subsidiary predecessors. With respect to H_2S content, the contract for gathering, dehydration, and compression services required that gas delivered to the gathering system meet the Questar pipeline quality specifications. Initially, treatment occurred at the well sites. Later, some central H_2S towers were installed to treat troubled areas of the field, but much of the treatment still occurred at the well site.

The Questar pipeline allowed a maximum of 1/4 grain of H_2S per 100 cubic feet and 5 grains of total sulfur per Mcf. There is no suggestion that any of the gas involved in this appeal was sweetened to a significantly lower level of H_2S than allowed by the Questar pipeline for some other purpose. Therefore, to the extent gas was desulphurized, it was necessary to put the production into marketable condition. The costs of this function therefore are not deductible in calculating royalty value.

Because most of the desulphurization was performed at the well sites, and the central H_2S towers presumably were located on the Chapita Wells Unit or the Stagecoach Unit or on ML 47045, gas used as fuel in desulphurization equipment is not royalty-bearing.

V. Allocation of Costs Between Gathering/Treatment and Transportation, and Allocation of Processing Plant Costs Between Treatment and ProcessingC "Unbundling"

The 2012 Audit Report noted that in initially computing and paying royalties, EOG deducted all costs incurred under the gathering, compression, and dehydration contracts as well as gas volumes used as fuel in the compressors. APP 000003. This, of course, was consistent with EOG's legal position. The Report then observed that on October 7, 2009, ONRR (then MMS) issued a "Dear Reporter" letter giving the agency's guidance to operators of the Manzanares gas system in New Mexico "on what costs could be considered proper transportation deductions and which part of their bundled fee were actually costs of placing production into 'marketable condition.'" *Id*. The process of allocating costs paid as a single combined fee or price for services that include both functions necessary to put gas into marketable condition (*e.g.*, gathering and treatment) and either transportation or processing is referred to as "unbundling." This question usually arises in the context of arm's-length contracts for services, as is the case in this appeal.

The 2012 Audit Report further noted that on October 6, 2010, ONRR issued another "Dear Reporter" letter containing more general guidance to royalty reporters captioned "Re: Guidance for Valuing Gas for Royalty Purposes - Transportation Systems and Processing Plants - Onshore Federal Leases" (hereinafter the "ONRR 2010 Unbundling Guidance").[69] *Id*. The ONRR 2010 Unbundling Guidance contemplates that ONRR would obtain information from the party who contracts with the lessees/operators to provide services. This information may include "actual or replacement costs where practicable," as well as "capital costs or operating and maintenance costs, overhead, depreciation, and return on investment for the various components comprising the transmission and/or processing facilities." ONRR would then allocate those costs between systems and facility components associated with deductible and non-deductible functions to derive factors for each that the lessees would use in their royalty calculations. ONRR 2010 Unbundling Guidance, pp. 2-3.

ONRR has reviewed a number of systems and processing plants that move or process gas produced from Federal leases, and has prescribed allocation factors in an "unbundling cost analysis" (UCA) for 30 such systems or plants,[70] including the Chipeta plant.[71] However, the ONRR UCAs do not include the Questar/QEP Resources gathering system involved in this case or the Red Wash, Stagecoach, or Iron Horse processing plants.

The 2012 Audit Report noted that ONRR had not "audited" the Questar gathering system involved here, and proposed that EOG and SITLA "settle this audit by adhering to the same

[69] The document is available at https://www.onrr.gov/unbundling/pdf/DRL_Transportation_ Systems_and_Processing_Plants_October_6_2010.pdf.

[70] These are found at https://www.onrr.gov/Unbundling/index.htm.

[71] Administrative Record, Chipeta Plant UCA. *See also*, https://www.onrr.gov>unbundling>pdf>Chipeta-Plant-Example (Chipeta-Plant-Example.pdf).

methodology ONRR has used to calculate transportation allowances in similar situations." *Id*. The 2012 Audit Report then proposed to disallow 65 percent of the costs EOG paid under the gathering, compression, and dehydration contract as non-deductible costs on the ground that this "is the percentage of bundled costs that were found to be non-deductible in ONRR's review of the Manzanares system." APP 000004. The SITLA auditors believed this factor was reasonable because much of the fees paid to QEP Resources "are for treatment and gathering of gas production before it reaches the Red Wash plant . . . ." *Id*. The 2018 Audit Report did not include any further discussion of this issue.

EOG argues that "[t]here is no reasonable correlation between the Manzanares gathering system in New Mexico, which is designed to handle coalbed methane produced in the San Juan basin, and the Uintah Basin natural gas system at issue in this matter." EOG Petition, p. 10.[72] SITLA says that in the audit for the 2007-2011 period, it used the UCA for the Manzanares system "in the absence of any better information being provided by EOG." SITLA Opening Brief, p. 17. SITLA further said that it "continues to welcome submission of better information by EOG (for example, the UCA that EOG has used in paying the United States its royalties in this field). Newer, better information can certainly be incorporated into the amount SITLA demands." *Id*. SITLA reiterated this position summarily in its reply brief. SITLA Reply Brief, pp. 17-18.

EOG is correct that SITLA may not decide to use ONRR's UCA for the Manzanares system in New Mexico as a proxy UCA for the QEP Resources gathering system involved in this matter simply because "better information" was not available. There is no evidence whatsoever in the record regarding either the operational and design similarities or operational and design differences between the Manzanares system and the QEP Resources system. There is nothing in the record that would indicate that the costs of the various functions and components of the Manzanares system are essentially the same as the costs of the functions and components of the QEP Resources system. The apparent lack of "better information" does not give SITLA the authority to arbitrarily pick some other system somewhere else and apply ONRR's UCA for that system to the system that handles EOG's gas here. SITLA's attempt to apply the Manzanares system UCA to the QEP Resources system involved in this matter is arbitrary and legally untenable.

If EOG was in possession of more information relevant to allocation of costs of the gathering system or of any of the processing plants, and if EOG refused to produce that information when SITLA asked for it or demanded it, SITLA's remedy under the lease terms would be either to cancel the lease administratively (*see* notes 17 and 18, *supra*), or to sue to compel production of the information.[73] The remedy for lack of information is not to select

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[72] *See* https://www.ogj.com/general-interest/companies/article/17213919/coalbed-methane-pipeline-scheduled-for-san-juan-basin. ONRR's October 7, 2009 UCA for the Manzanares system is at https://www.onrr.gov/unbundling/pdf/DRL_Manzanares_October_7_2009.pdf.

[73] The State does not have the equivalent of the Federal civil penalty authority granted to ONRR to enforce document production under section 111 of the Federal Oil and Gas Royalty

some other gas plant as a "proxy" with no evidence that the costs, components, and processes in both plants are essentially the same.[74]

ONRR's unbundling calculation for the Chipeta processing plant would apply to unbundling costs for gas processed through that plant. ONRR's UCA for the Chipeta plant would be the UCA that EOG would use in calculating royalties on production from the Federal leases that was processed through that plant, and, therefore, should be the UCA used in calculating royalty owed to SITLA under the Federal floor proviso. However, for the same reasons that it would be improper to use the UCA for the Manzanares system as a proxy for the QEP Resources gathering system here, it would be improper to use the Chipeta plant UCA as a proxy for the Stagecoach, Iron Horse, or Red Wash plants.

In the absence of an ONRR-calculated UCA for a particular plant, ONRR has published suggested methods for calculating UCAs for gathering/transportation systems and for processing plants. ONRR's "How to Calculate a Transportation UCA" is at https://www.onrr.gov/unbundling/pdf/How-to-calculate-a-Transportation-UCA.pdf. ONRR's "How to Calculate a Processing UCA" is at https://www.onrr.gov/unbundling/pdf/How-to-calculate-a-Processing-UCA.pdf.

ONRR's suggested methods for calculating a transportation UCA or a processing UCA were not promulgated as rules under the notice-and-comment rulemaking procedures of the Administrative Procedure Act, 5 U.S.C. § 553, and do not have the force and effect of law. They do, however, explain ONRR's approach in allocating costs between deductible and non-deductible costs, and what ONRR will accept as an allocation calculation, and thus are relevant in applying the Federal floor proviso in the state lease terms. If use of these suggested methods to "unbundle" and allocate non-deductible and deductible costs that are combined in one fee is acceptable to ONRR for Federal royalty calculation purposes, it will be acceptable to SITLA in calculating minimum royalty value under the Federal floor proviso. How each of these suggested methods will apply to the facts of this proceeding, and how cost accounting issues should be resolved, is properly the subject of the second phase of this appeal. But as a matter of law, use of ONRR's suggested approach is proper.

VI. Processing Costs and Processing Cost Deduction Cap

The 2018 Audit Report (at p. 4) identifies the following as "Issue 3": "Greater than the allowed 2/3 maximum processing deduction on gas processed through the Chapita plant." The Report then stated: "Although only a small fraction of EOG's gas is processed through the Chapita plant, it appears EOG does not check to see if the amount paid in processing fees is greater than 2/3 of liquids sales proceeds." [75] *Id*. The 2018 Audit Report does not explain how

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Management Act, 30 U.S.C. ' 1721. The State Legislature would have to enact such a statute.

[74] The Board has not made, and is not making here, any finding or determination that EOG withheld any information in its possession.

[75] The references to the "Chapita plant" presumably are to the Chipeta plant.

the auditors determined that EOG failed to "check," or whether EOG actually had taken excessive processing cost deductions and therefore had underpaid royalties.

In its Petition for Review (p. 11), EOG argues that SITLA "selectively interprets the rules," *i.e.*, the Federal gas valuation rules at 30 C.F.R. § 1206.158(c)(2) (formerly section 206.158(c)(2)), which limit deductions for processing costs to 66⅔ percent of the value of each gas plant product. EOG alleges that SITLA ignores the provision in paragraph (c)(3) of that section, which allows ONRR to approve a processing deduction in excess of that limitation if the lessee demonstrates that the excess costs incurred were "reasonable, actual, and necessary."

In its Response to EOG's Petition for Review (p. 11), SITLA argues that EOG has provided no evidence that it either requested or received approval for an excess allowance. SITLA further maintained that section 4(b) of the lease instruments s provides additional, independent authority for the 66⅔ percent limit on processing cost deductions.

EOG's Opening Brief did not address the processing costs issue. SITLA's Opening Brief provides some additional detail regarding what SITLA asserts are errors in EOG's processing cost calculations:

> EOG also exceeds the two-thirds processing deduction limit by ignoring the ONRR-mandating sequence of applying the transportation deduction (50% limit) to the gross price first, and then applying the processing deduction (66.67% limit) to whatever remains (net of the transportation deduction). See 30 C.F.R. 1206.158(c)(2). EOG's practice of combining the transportation and processing deductions rather than following the required sequence allows EOG to ultimately take deductions for processing which would exceed the ONRR limit if the required sequence were followed.

SITLA Opening Brief, p. 18. SITLA's brief does not give any more detail about what SITLA had found that revealed this problem, or to what extent it resulted in royalty underpayments. Subsequently, as part of its argument that the lease instrument allows deductions only for processing costs and no other costs (discussed above), SITLA makes the cryptic statement that the lease royalty clause "provides that only actual 'processing' costs may be deducted from the value of NGLs and processed residue gas." *Id*., p. 20.

EOG responded by arguing that "EOG's leases clearly distinguish 'gas' from 'processed or manufactured or extracted products' subject to the two-thirds cap." EOG Response Brief, p. 14. EOG further observed that the definition of "gas plant products" in the Federal valuation rules at 30 C.F.R. § 1206.151 specifically excludes residue gas. *Id*.

Both parties' arguments are correct in certain respects and are problematic in certain respects, and give rise to some confusion. It is necessary to clarify the legal principles that apply to the processing cost deduction to ensure that recalculation of royalties in the second phase of this proceeding is done correctly.

The royalty clause of the respective lease instruments provides in relevant part:

> Provided expressly that the reasonable market value of <u>processed or manufactured or extracted products</u>, for the purpose of computing royalties hereunder, shall be the value after deducting the costs of processing, extracting or manufacture, except that <u>the deduction for such costs may not exceed two-thirds of the amount of the gross of any such products without approval by the LESSOR</u> and, provided further that the market value of extracted, processed or manufactured products used in the computation of royalties hereunder shall not be less than the value used by the United States in its computation of royalties on similar products resulting from production of like grade and quality in the same field. [Emphasis added.]

The Federal royalty valuation rules at 30 C.F.R. § 1206.158(c) and (d) (2011-2020), formerly section 206.158(c) and (d) (1988-2010), under which the minimum royalty value must be computed under the Federal floor proviso, provide in relevant part:

> (c)(1) Except as provided in paragraph (d)(2) of this section, the processing allowance shall not be applied against the value of the residue gas. . . .
>
> (2) Except as provided in paragraph (c)(3) of this section, the processing allowance deduction on the basis of an individual product shall not exceed 66 2/3 percent of the value of each gas plant product determined in accordance with § 1206.153 of this subpart (such value to be reduced first for any transportation allowances related to postprocessing transportation authorized by § 1206.156 of this subpart).
>
> (3) Upon request of a lessee, ONRR may approve a processing allowance in excess of the limitation prescribed by paragraph (c)(2) of this section. The lessee must demonstrate that the processing costs incurred in excess of the limitation prescribed in paragraph (c)(2) of this section were reasonable, actual, and necessary. . . . Under no circumstances shall the value for royalty purposes of any gas plant product be reduced to zero.
>
> (d)(1) . . .
>
> (2)(i) If the lessee incurs extraordinary costs for processing gas production from a gas production operation, it may apply to ONRR for an allowance for those costs which shall be in addition to any other processing allowance to which the lessee is entitled pursuant

> to this section. Such an allowance may be granted only if the lessee can demonstrate that the costs are, by reference to standard industry conditions and practice, extraordinary, unusual, or unconventional.

The royalty clause of the subject leases and the Federal valuation rules impose the same requirements in almost all respects.

First, EOG is correct that residue gas is not a processed, manufactured, or extracted product, either under the lease terms or under the definition in the Federal valuation rules at 30 C.F.R. § 1206.151 (formerly 30 C.F.R. § 206.151). Under both the express lease term and the Federal rules, processing costs may <u>not</u> be deducted in computing the royalty value of residue gas. Processing costs may be deducted only in computing the royalty value of royalty-bearing extracted products such as NGLs.[76]

Second, under both the lease terms and the Federal rules, the processing cost deduction is to be applied in calculating the royalty value of extracted products such as NGLs after transportation costs have been deducted from a sales price for the extracted products received at a remote downstream point of sale (or from a downstream measure of value that is the basis for calculation of royalty value). SITLA is correct in this regard. This is expressly stated in section 1206.158(c)(2) in the Federal rules. It is also implicit in the royalty clause of the State leases. As stated previously, royalty is due on the value of production at the lease (or unit), not the value of production at a downstream sales or valuation point. If NGLs are sold at a downstream point of sale away from the lease or unit and that sales price is the basis for calculating royalty value, and if EOG uses two-thirds of that price to calculate the maximum processing cost deduction, then the processing cost deduction easily could exceed two-thirds of the value of the NGLs at the lease.

The present record does not reveal whether EOG's processing cost deductions in fact have exceeded the two-thirds limit, properly calculated under both the Federal rules and the lease terms.

Third, contrary to both SITLA's and EOG's arguments, ONRR has no authority to approve a processing cost allowance in excess of the two-thirds limit for NGLs derived from processing gas produced from or allocated to a state lease, or to approve an extraordinary cost allowance that could be applied against the value of residue gas produced from or allocated to a state lease. The Federal processing allowance regulations quoted above were promulgated under

[76] The only possible exception, under the Federal rules, is if ONRR grants an "extraordinary cost" allowance under subsection (d)(2). EOG has neither asserted nor suggested that it has obtained or applied for such an extraordinary cost allowance for gas produced from or allocated to Federal leases that is processed in the same plants. What SITLA meant when it said in its opening brief quoted above (at p. 20) that the lease instrument itself "provides that only actual 'processing' costs may be deducted from the value of NGLs and processed residue gas" is unclear. But to the extent SITLA meant to say that processing costs, as a general matter, could be deducted in determining the royalty value of residue gas, SITLA would be incorrect.

the authority of the Federal mineral leasing laws, specifically, the MLA at 30 U.S.C. § 189 and the Mineral Leasing Act for Acquired Lands at 30 U.S.C. § 359. Those statutes, and the rules promulgated thereunder, apply to Federal mineral estate and Federal leases and production from Federal leases. They do not grant the Secretary of the Interior and his delegates in the ONRR authority to approve excess processing allowances, or extraordinary cost allowances, for gas produced from or allocated to state leases.

The unitization of the state leases within the Chapita Wells Unit and the Stagecoach Unit under Federal unit agreement forms does not change this principle for those leases. Section 1 of the respective unit agreements that include those leases provides, under the heading "Enabling Act and Regulations":

> The Mineral Leasing Act of February 25, 1920, as amended, supra, and all valid pertinent regulations, including operating and unit plan regulations, heretofore issued thereunder or valid, pertinent, and reasonable regulations hereinafter issued thereunder are accepted and made a part of this agreement as to Federal lands, provided such regulations are not inconsistent with the terms of this agreement; <u>and as to non-Federal lands, the oil and gas operating regulations in effect as of the effective date hereof governing drilling and producing operations</u>, not inconsistent with the terms hereof or the laws of the State in which the non-Federal land is located, are hereby accepted and made a part of this agreement.

APP 000072, 000095 (emphasis added). The ONRR regulations governing processing allowances are not part of the operating regulations governing drilling and production operations.

However, if ONRR has approved a processing cost allowance for EOG in excess of the two-thirds limit, or has approved an extraordinary cost allowance, for gas produced from Federal leases which is processed in the same plants, that must be taken into account in calculating the minimum royalty value of gas produced from or allocated to the state leases under the Federal floor proviso. That is because the approved excess processing cost (or extraordinary cost) allowance is part of the calculation of the royalty value of the gas produced from the Federal leases. However, EOG has not mentioned any such approval.

In addition, under the express terms of the royalty clause of the subject leases quoted above, SITLA has authority to approve processing allowances that exceed the cap for gas produced from or allocated to state leases. That authority is independent of the Federal rules.

Finally, for the reasons explained in Part III of this analysis above, gas used as fuel in the Red Wash plant is royalty-bearing because the plant is located off all of the leases and units involved here. The value of the gas used as fuel is part of the cost of processing, and counts toward the two-thirds cap. Gas produced from or allocated to ML 3077, ML 3078, and ML 3055 in the Chapita Wells Unit that is used as fuel in the Stagecoach, Iron Horse, or Chipeta plants is royalty-free (and the value of that gas is not part of the costs of processing) because all three of those processing plants are located on the Chapita Wells Unit. However, gas that is allocated to ML 1299 in the Stagecoach Unit, or produced from ML 47045 or ML 45681, that is used as fuel in the Stagecoach, Iron Horse, or Chipeta plants is royalty-bearing because that gas is used as fuel off the lease or unit. The value of that fuel gas is part of the cost of processing and counts toward the two-thirds cap.

VII. Transportation Cost Deduction Cap

SITLA's 2018 Audit Report found that in "[s]ome months EOG's transportation deductions exceed ONRR's requirement that transportation deductions for both gas and liquids be no more than 50% of the sales price. EOG has been getting around this rule by passing excess gas transportation costs into its T9 calculation." APP 000008. SITLA's Opening Brief (pp. 17-18) further explains the second sentence of this quotation: "Evidence submitted by EOG indicates that in some months, EOG has impermissibly exceeded the 50% limit on gas transportation by passing gas transportation costs in excess of the 50% limit onto its liquids transportation deduction (relabeling them 'T9' and adding them to the 'T6' liquid transportation costs)."

In its Petition for Review (p. 10), EOG asserts that "SITLA does not acknowledge ONRR's regulation, 30 C.F.R. § 1206.109(c)(2)[77], allowing exceptions to exceed this limit[.]" SITLA's Response to EOG's Petition (p. 10) states that EOG has provided no evidence that it has applied for such relief. SITLA's Opening Brief adds (p. 18):

> While the regulations provide for potential relief from this 50% cap, such relief must be applied for, supported by an appropriate showing, and approved by ONRR (or SITLA). See 30 CFR 1206.156(c)(3). . . . SITLA has on past occasions granted relief from this 50% limit where its lessee has shown that it applied for and received such relief from ONRR. SITLA recognizes exceptions to the 50% limit in such cases as a function of implementing the lease=s federal floor provision.

EOG argues that the 50 percent cap does not apply to EOG's state leases because, under its theory, the value at the well provision entitles it to deduct all transportation and other costs incurred after the gas surfaces, and that the Federal regulations "cannot change the deal struck in the language of the leases." EOG Opening Brief, p. 10. EOG adds: "In any event, and in the

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[77] *Sic*. EOG presumably meant to refer to 30 C.F.R. § 1206.156(c)(3), which provides a mechanism for Federal lessees to apply for approval of a transportation allowance in excess of the 50 percent limit for gas, which is the regulation SITLA correctly cites in its Opening Brief, quoted below. Title 30 C.F.R. § 1206.109(c)(1) prescribes the same 50 percent limitation on transportation allowances for crude oil produced from Federal leases as section 1206.156(c)(1) prescribes for gas. Section 1206.109(c)(2), incorrectly cited in EOG's Petition, provides a mechanism for Federal lessees to apply for approval of a transportation allowance in excess of that limitation for crude oil.

alternative, EOG requests that it be allowed to exceed the 50% cap when implicated in the recalculation of royalties in this proceeding." *Id*.

Both parties' arguments are problematic. For the reasons explained in Parts I and II of this analysis above, EOG's position regarding the effect of the value at the well provision and its relationship to the Federal floor proviso is incorrect. Further, for the reasons explained in Part VI of this analysis above, ONRR does not have authority to approve excess transportation allowances for gas produced from or allocated to state leases. Thus, SITLA's apparent suggestion that ONRR could or would approve an excess transportation allowance for gas produced from or allocated to the leases involved in this appeal is misplaced.

Nor can SITLA exercise authority granted to the Secretary of the Interior and his delegates under the Federal mineral leasing laws and Federal rules. While the Federal floor proviso in the lease instruments requires the value of production to be not less than the value established under Federal regulations, that does not operate to grant additional authority to SITLA to administer, or issue approvals or denials under, Federal rules with respect to state leases. Thus, SITLA cannot purport to approve an application for a transportation allowance in excess of the 50 percent limit under the authority of Federal regulations on its own initiative. In applying the Federal floor proviso, SITLA and, ultimately, the state courts, necessarily have to interpret the Federal valuation rules. Indeed, the instant appeal is an excellent example. But SITLA cannot take actions under the purported authority of the Federal rules.

This does not mean that transportation costs are not deductible under the terms of the state leases, independent of the Federal valuation rules. As explained previously, the provision for royalty as a defined percentage of the value of all gas "saved or sold from the leased premises" means that royalty is due on the value of production at the lease (or unit), and not on the value at a remote downstream location. But for the reasons explained in Part I of this analysis above, applying the Federal floor proviso requires that royalty value be not less than the value of the production determined under the Federal valuation rules. That necessarily includes the both the proper classification of costs under the Federal rules and the 50 percent limitation on allowances for actual transportation costs prescribed in section 1206.156(c) and its predecessor codification at former section 206.156(c).

SITLA states, as quoted above, that it has "granted relief from this 50% limit where its lessee has shown that it applied for and received such relief from ONRR. SITLA recognizes exceptions to the 50% limit in such cases as a function of implementing the lease=s federal floor provision." The Board agrees that if EOG has applied for and received from ONRR approval of an excess transportation allowance for gas produced from or allocated to EOG's Federal leases that is transported to the same points of sale under the same transportation contract and transportation arrangements as gas produced from or allocated to EOG's state leases, SITLA must take the excess transportation allowance into account in determining the minimum royalty value of that gas under the Federal floor proviso. That is because the approved excess transportation allowance is part of the calculation of the royalty value of the gas produced from the Federal leases.

The Board notes that there is a potential solution to the regulatory uncertainty with respect to the gas produced from or allocated to state leases. The SITLA Director could adopt a regulation under the authority of Utah Code Ann. § 53C-1-302(1) that would allow SITLA to approve transportation allowances in excess of 50 percent of the value of the gas produced from or allocated to state leases that SITLA administers.

Whether EOG, as an accounting matter, improperly attributed any costs of transporting residue gas on the Questar pipeline to transporting NGLs extracted through processing will be determined in the second phase of this proceeding. If EOG did do so, then those costs must be properly accounted for as part of the costs of transporting residue gas, and will count toward the 50 percent cap.

As noted in the Findings of Fact above, it appears from the stipulated facts that all of the NGLs extracted by processing at each of the processing plants involved in this appeal were sold at the respective plants. ONRR regulations at 30 C.F.R. § 1206.156 (2011-2020), formerly 30 C.F.R. § 206.156 (1988-2010), provide in relevant part:

> (a) Where the value of gas has been determined pursuant to § 1206.152 or § 1206.153 of this subpart at a point (e.g., sales point or point of value determination) off the lease, ONRR shall allow a deduction for the reasonable actual costs incurred by the lessee to transport unprocessed gas, residue gas, <u>and gas plant products from a lease to a point off the lease including, if appropriate, transportation from the lease to a gas processing plant off the lease</u> and from the plant to a point away from the plant.
>
> (b) <u>Transportation costs must be allocated among all products produced and transported</u> as provided in § 1206.157.
>
> (c)(1) . . .
>
> (2) Except as provided in paragraph (c)(3) of this section, for gas production valued in accordance with § 1206.153 of this subpart [*i.e.*, processed gas], the transportation allowance deduction on the basis of a sales type code may not exceed 50 percent of the value of the residue gas or gas plant product determined under § 1206.153 of this subpart. For purposes of this section, natural gas liquids will be considered one product. [Emphasis added.]

Thus, the portion of the costs of transporting gas produced from or allocable to ML 3077, ML 3078, and ML 3355 in the Chapita Wells Unit and ML 1299 in the Stagecoach Unit, or produced from any of the non-unitized state leases, to the Red Wash plant that is properly allocable to NGLs extracted by processing and sold at that plant may be deducted as a transportation allowance in calculating the royalty value of the NGLs. That deduction may not exceed 50 percent of the value of the NGLs. Similarly, the portion of the costs of transporting gas (1) allocable to ML 1299 in the Stagecoach Unit or (2) produced from ML 47045 or ML 45681 to the Stagecoach, Iron Horse, or Chipeta plants that is properly allocable to NGLs extracted by processing and sold at those plants may be deducted as a transportation allowance in calculating the royalty value of the NGLs. That deduction also may not exceed 50 percent of the value of the NGLs. Because NGLs extracted at the Stagecoach, Iron Horse, or Chipeta plants from gas produced from or allocable to ML 3077, ML 3078, and ML 3355 in the Chapita Wells Unit are sold on the unit, no transportation allowance may be taken in calculating the royalty value of those NGLs.

As explained in Part III of this analysis above, gas used as fuel in compressors along the Questar pipeline downstream of the pipeline inlet is royalty-bearing, and the value of the volumes used as fuel is a cost of transportation and may be deducted in calculating the value of the total royalty-bearing volume. The deducted amount counts toward the 50 percent cap on allowable transportation costs. The sum of transportation costs paid in cash and the value of volumes used as fuel along the pipeline may not exceed 50 percent of the value of the total of the royalty-bearing volumes—*i.e.*, the delivered volumes plus the fuel-use volumes.

VIII. Statute of Limitations C Action by the State to Collect Unpaid Royalties

In its Petition for Review of SITLA's order, EOG asserted that

> any amounts sought to be recovered which accrued more than six years ago would be subject to the limitations in Utah Code Ann. § 78-B-2-309, and, in any event, SITLA's right to recover any amount that accrued more than seven years ago would be absolutely barred by the statute of repose contained in Utah Code Ann. § 78B-2-201. *See Garfield County, Utah v. United States*, 2017 UT 41, & 18 (Utah 2017) (Section 201 is a statute of repose.)

EOG Petition, p. 13.

A. The Statute of Limitations Does Not Bar an Administrative Order.

Utah Code Ann. § 78B-2-201 reads:

> **78B-2-201. Actions by the state.**
>
> (1) The state may not bring an action against any person for or with respect to any real property, its issues or profits, based upon the state's right or title to the real property, unless:
>
> (a) the right or title to the property accrued within seven years before any action or other proceeding is commenced; or
>
> (b) the state or those from whom it claims received all or a portion of the rents and profits from the real property within the immediately preceding seven years.

> (2) The statute of limitations in this section runs from the date on which the state or those from whom it claims received actual notice of the facts giving rise to the action.

Section 78B-2-309 provides in relevant part:

> **78B-2-309. Within six years -- Mesne profits of real property -- Instrument in writing -- Fire suppression.**
>
> (1) An action may be brought within six years:
>
> . . .
>
> (b) subject to Subsection (2), upon any contract, obligation, or liability founded upon an instrument in writing . . . .[78]

Both of these provisions bar an "action" if not brought within the time prescribed. Section 78B-2-101(1) defines the term "action" as follows: "(1) The word 'action' as used in this chapter includes counterclaims and cross-complaints and all other civil actions in which affirmative relief is sought." (Emphasis added.)[79] Thus, the statutes of limitations in the quoted sections apply to judicial lawsuits. They do not operate to bar administrative orders such as the SITLA orders involved in this appeal. *Morgan v. Dep't. of Commerce*, 2017 UT App. 225, 414 P.3d 501, 503-504 (2017); *Phillips v. Dep't. of Commerce*, 2017 UT App 84, 397 P.3d 863, 867 (2017); *Rogers v. Division of Real Estate*, 790 P.2d 102, 105-106 (Utah Ct. App. 1990).[80]

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[78] Subsection (1)(a) (omitted from the quotation) bars an action for "the mesne profits of real property" if not brought within six years. An action for the "mesne profits of real property" is an action "to recover profits derived from land, while the possession of it has been improperly withheld[.]" *Black's Law Dictionary*, Revised 4th Ed. (West Publishing Co., 1976), at 1376. Thus, it is in the nature of an action for trespass damages and is not relevant to a claim for unpaid royalties under a mineral lease. This section was renumbered from former section 78-12-23(2) as part of a recodification and revision of Title 78 in Laws of Utah 2008, Chapter 3 (HB 78, "Title 78 Recodification and Revision," Line 1113).

[79] Section 78B-2-101 was renumbered from former section 78-12-5.3 without change as part of the 2008 recodification of Title 78 (Laws of Utah 2008, Chapter 3 (HB 78, "Title 78 Recodification and Revision," Line 1042)).

[80] In *Phillips*, the court observed that "the absence of an applicable statute of limitation did not grant the agency unlimited time during which to proceed with administrative enforcement[,]" 397 P.3d at 867, because the doctrine of laches would come into play at some point.

B. Utah Code Ann. § 78B-2-201(1)(b) Would Apply to a Lawsuit by the State to Enforce a Final Administrative Order to Pay Royalties Due.

At this point in the instant appeal, SITLA's order is under administrative review by this Board under Utah Code Ann. § 53C-1-304(2). This Board's decision issued under subsection (4) of that section is subject to judicial review in the Utah Court of Appeals under subsection (5) and Utah Code Ann. § 63G-4-403. The question of whether either of the two limitations provisions quoted above would apply to a suit by SITLA or the State to enforce a final decision of the Board requiring payment of additional royalties technically is not before the Board, because at this point there is no suit to enforce a final decision of the Board requiring EOG to pay additional royalties. However, to facilitate review in the Court of Appeals, and to better facilitate the potential for an agreed resolution in the next phase of this appeal (and thereby avoid the high costs of discovery and an evidentiary hearing on the accounting issues), the Board believes it is appropriate to address that question in this analysis.

The issue of whether either Utah Code Ann. § 78B-2-201 or § 78B-2-309 would apply to a suit for enforcement of a Board decision appears to have been at least implicitly resolved in the affirmative as to section 78B-2-201, and in the negative as to section 78B-2-309, in *Trail Mountain Coal Co. v. Division of State Lands*, 884 P.2d 1265 (Utah Ct. App. 1994), *affirmed in part and reversed in part*, 921 P.2d 1365 (Utah 1996). The history of section 78B-2-201, which limits actions by the State for or with respect to any real property or its issues or profits, is revealing. From its enactment in 1872 through 2008, the predecessor provision, former Utah Code Ann. § 78-12-2, read:

> The State will not sue any person for or in respect to any real property, or the issues or profits thereof, by reason of the right or title of the state to the same, unless: (1) such right or title shall have accrued within seven years before any action or other proceeding for the same shall be commenced; or (2) the state or those from whom it claims shall have received the rents and profits of such real property, or some part thereof, within seven years.

This section was renumbered as section 78B-2-201 in 2008 as part of the recodification of Title 78 (Laws of Utah 2008, Chapter 3 (HB 78, Line 1068)). The Legislature then amended this section in 2009 in Ch. 146 of the 2009 General Session laws, which enacted SB 170. Section 8 of that statute read:

> Section 8. **Section 78B-2-201** is amended to read:
>
> **78B-2-201. Actions by the state.**
>
> The state may not bring an action against any person for or with respect to any real property, its issues or profits, based upon the state's right or title to the real property, unless:
>
> (1) the right or title to the property accrued within seven years before any action or other proceeding is commenced; or

(2) the state or those from whom it claims received all or a portion of the rents and profits from the real property within the immediately preceding seven years.

The amendment made the following changes:

a. In the introductory language, it changed “will not sue any person” to “may not bring an action against any person”; changed “or the issues or profits thereof” to “its issues or profits”; and changed “by reason of the right or title of the state to the same” to “based upon the state’s right or title to the real property;”

b. In what was then subsection (1), it changed “such right or title shall have accrued within seven years” to “the right or title to the property accrued within seven years” and changed the words “before any action or other proceeding for the same shall be commenced” to “before any action or other proceeding is commenced,” thus eliminating the words “for the same;” and

c. In what was then subsection (2), it changed “shall have received the rents and profits of such real property, or some part thereof” within seven years to “received all or a portion of the rents and profits from the real property within the immediately preceding” seven years.

None of these revisions changed the substantive meaning of this section.

The Legislature further amended this section in 2015 by enacting Ch. 2 of the 2015 Special Session 1 Laws (HB 1001), titled “Statute of Limitations Amendments.” It read:

Section 1. Section **78B-2-201** is amended to read:

78B-2-201. Actions by the state.

(1) The state may not bring an action against any person for or with respect to any real property, its issues or profits, based upon the state’s right or title to the real property, unless:

(a) the right or title to the property accrued within seven years before any action or other proceeding is commenced; or

(b) the state or those from whom it claims received all or a portion of the rents and profits from the real property within the immediately preceding seven years.

(2) The statute of limitations in this section runs from the date on which the state or those from whom it claims received actual notice of the facts giving rise to the action.

Section 2. **Effective date.**

If approved by two-thirds of all the members elected to each house, this bill takes effect upon approval by the governor, or the day following the constitutional time limit of Utah Constitution, Article VII, Section 8, without the governor=s signature, or in the case of a veto, the date of veto override.

Section 3. **Retrospective operation.**

This bill has retrospective operation to March 12, 1953.

This amendment renumbered the previous language as subsection (1) without change (bringing section 78B-2-201 to its present form), added a tolling provision as a new subsection (2), and made the statute as amended retroactive to March 12, 1953.

The pre-2009 version of the statute (former section 78-12-2, the original statute enacted in 1872) was at issue in *Trail Mountain Coal Co.* In that case, the Division of State Lands audited royalty payments under various State coal leases. The Division determined that the lessee (Trail Mountain Coal) had underpaid royalties for the period 1979 through 1984, on the ground that royalties should have been paid on a rate of eight percent of the value of the coal produced rather than on a rate of 15 cents per ton. The Division issued a letter dated October 15, 1985, assessing royalty due of over $3.3 million, together with interest and a late payment penalty. The trial court entered judgment for the Division, determining that Trail Mountain owed nearly $3.7 million in unpaid royalties, together with prejudgment interest at the rate of 6 percent on each delinquent payment (totaling approximately $2 million), for a total judgment of approximately $5.7 million. Trail Mountain asserted that the State was time-barred from collecting some of the amounts.

With respect to the statute of limitations, the Utah Court of Appeals held that former section 78-12-2 by its terms applied to the State and its claim for royalties, and that the six-year statute of limitations for actions founded upon written contracts in former section 78-12-23(2) (now section 78B-2-309(1)(b)) did not. 884 P.2d at 1271.

On appeal, Trail Mountain argued that six-year statute of limitations for actions upon written contracts in former section 78-12-23(2) applied, and that the language “by reason of the right or title of the state to the same” in former section 78-12-2 (now section 78B-2-201) limited that provision to cases where the state sues for the right or title to the real property, *i.e.*, suits for adverse possession. The Utah Supreme Court agreed with the Court of Appeals that former section 78-12-2 applied to the State’s claim for unpaid royalties and that the six-year limitation provision then codified at former section 78-12-23(2) did not. The Utah Supreme Court held:

> A plain reading of the statute [*i.e.*, former section 78-12-2, now section 78B-2-201] reveals that it applies to actions brought by the state as a consequence of the state’s claim of right to real property or issues or profits derived from real property. If, as Trail Mountain claims, the statute were limited to adverse possession claims, the language “or the issues or profits thereof” would be

> rendered superfluous. "This court will not construe a statute in such a way as to render certain viable parts meaningless and void." *Nelson v. Salt Lake County*, 905 P.2d 872, 876 (Utah 1995). In this case, the Division is alleging that Trail Mountain withheld issues or profits derived from leased school trust lands, and the Division, as a state agency, brought suit by virtue of its right to receive those profits. This lawsuit therefore fits within the express terms of § 78-12-2, and consequently, we uphold the ruling of the Court of Appeals as to its applicability.

921 P.2d at 1372. Under the Utah Supreme Court's ruling in *Trail Mountain Coal*, section 78B-2-201 applies because mineral lease royalties are "issues or profits" derived from State-owned land. EOG's argument that "any amounts sought to be recovered which accrued more than six years ago would be subject to the limitations contained in Utah Code Ann. ' 78B-2-309," EOG Petition, p. 13 (quoted above), is contrary to the holding in *Trail Mountain Coal*.

C. An Action By the State to Enforce a Final Administrative Decision to Pay Additional Royalty in the Instant Case Would Be Timely as a Matter of Law under Utah Code Ann. § 78B-2-201(1)(b) If the Leases Are Producing When the State Brings the Action.

Trail Mountain Coal involved an assessment by the Division of State Lands for unpaid royalties and interest issued on October 15, 1985, for a period beginning in 1979. Though the court in *Trail Mountain Coal* held that former section 78-12-2 (now section 78B-2-201) applies to claims for unpaid royalties because royalties are "issues and profits" of State-owned real property, neither the Utah Court of Appeals nor the Utah Supreme Court further addressed how the statute operates.

Subsection (2) of the former section 78-12-2 barred the State from suing to recover the issues or profits of real property "unless . . . (2) the state or those from whom it claims shall have received the rents and profits of such real property, or some part thereof, within seven years." This provision was carried over into subsection (2) of the 2009 amendment and in turn into subsection (1)(b) of the current section 78B-2-201, as amended in 2015. As noted previously, the words in the original statute "shall have received the rents and profits of such real property, or some part thereof" within seven years were changed in 2009 to "received all or a portion of the rents and profits from the real property within the immediately preceding" seven years. The substance and meaning of both versions of the language is the same.

It would appear that the term "rents and profits" from the property refers to the "issues and profits" from the property in the introductory clause. Why the Legislature used "issues" in one clause and "rents" in the other is unknown. However, both "issues and profits" and "rents and profits" refer to the financial benefits derived from the real property, and no difference in meaning between the two phrases is discernible.

Thus, the structure of this statute from the beginning has been bifurcated between suits by the State involving title to the real property itself (or rights to its use or possession) on the one hand, and suits to recover financial benefits derived from the property that are owed to the State on the other. In a case involving title or right to possession or use of the real property, the State must bring suit within seven years of the date the State's title or right accrued, unless the running of the limitations period is tolled under the new subsection (2) of the 2015 statute in the event the State somehow was unaware of its title or right. In a case involving financial benefits derived from the real property, the State must bring suit within seven years of when it "received all or a portion of the rents and profits from the real property[,]" unless the running of the limitations period would be tolled under the new subsection (2) because the State had not received actual notice of the facts giving rise to its right of action.

It seems clear from both the wording and the structure of the statute that subsection (2) of the original statute and the 2009 amendment, and the current subsection (1)(b), applies by its terms to suits for unpaid royalties due. Under the express language of subsection (1)(b), as quoted above, the seven-year period runs from the date on which the State "received all or a portion of the rents and profits from the real property[.]" (Emphasis added.) This language does not sayCand does not implyCthat the seven-year period begins to run on the date that a particular payment was owed to the State, or that the limitations period runs seven years after the date a particular payment was due. On the contrary, by its plain language, the period runs from the date of receipt by the State of any portion of the financial benefits derived from the property, not from when a lessee or tenant or user of State property owes an amount the State has not received.

In the case of ongoing regular periodic royalty payments from mineral leases, this would mean that a suit for unpaid royalties due would be timely if brought within seven years of the date of the State's receipt of the last royalty payment made under the lease. In theory, this would imply that the state could, in 2021, bring suit for any royalty the State believes is due from a currently producing lease since the lease began production. EOG and other lessees likely would argue that this is no statute of limitations at all. The answer to that is that it is a statute of limitations, but one that does not restrict the State very muchCif the State doesn't bring suit within seven years of the last royalty payment received, then suit would be barred.

The Legislature, to be sure, didn't have oil and gas leases (or coal or other mineral leases) in mind when it first enacted the relevant language in 1872. However, the Legislature did not change the substance or meaning of the language when it considered and amended the statute in 2009, after decades of State oil and gas leasing and production, and then kept the language in 2015. If the Legislature chooses not to enact a more restrictive or more traditional statute of limitations, then EOG's quarrel is with the Legislature and it must seek its remedy there. Neither this Board nor the courts can read into a statute language that is not there.

The Board notes that in practical effect, the lack of a more restrictive limitations period is not likely to open lessees such as EOG to numerous new claims for unpaid royalties going back many years. First, at some point, the doctrine of laches would come into play under the facts of a particular case if SITLA were to simply sit on its rights. *See*, *e.g.*, *Fundamentalist Church v. Lindberg*, 2010 UT 51, 238 P.3d 1054 (2010), and cases cited. Second, to assert a claim for unpaid royalties, the State, through SITLA, must audit the lessee's payments, which requires production and examination of documents and related data. If a lessee has lawfully disposed of old documents regarding sale and disposition of the production, then the information the State needs to conduct an audit will not be available. In that situation, there will be no basis on which to assert that the lessee underpaid. This gives the State every incentive to stay current on its audits of lessees and royalty payors and not let potential claims grow stale.

In the present appeal, the leases involved are still producing, and EOG continues to pay royalties to the State, which the State continues to receive. It follows that as a matter of law, section 78B-2-201(1)(b) would not bar a lawsuit by the State to enforce a final administrative decision requiring EOG to pay additional royalties owed for the periods at issue in this appeal if the leases are still producing when the State brings such an action.

D. EOG's Argument that Section 78B-2-201 Would Bar an Action to Enforce a Final Administrative Order to Pay Royalty Because It Is a Statute of Repose Is Misplaced.

EOG further argues that "SITLA's right to recover any amount that accrued more than seven years ago would be absolutely barred" under section 78B-2-201 because section 78B-2-201 is a statute of repose rather than a statute of limitations, citing *Garfield County v. United States*, 2017 UT 41, 424 P.3d 46 (Utah 2017). EOG Petition, p. 13. In *Garfield County*, the Utah Supreme Court answered a certified question from the United States District Court for the District of Utah regarding whether section 78B-2-201(1), as amended in 2009, and its predecessor are statutes of limitations or statutes of repose.[81] The case involved the State's claims to rights-of-way under Revised Statute (R.S.) 2477. The court expressed the view that subsection (1) (now subsection (1)(a)) is a statute of repose by its plain language.[82] However, the court went on to nevertheless construe the statute as a statute of limitations with respect to the State's right-of-way claims under R.S. 2477, because to do otherwise would lead to the absurd result of the State automatically losing title to its rights of way without any opportunity to prevent the loss. The court emphasizedCtwiceCthat the Federal court had not asked it to interpret the statute as amended in 2015. 424 P.3d 51 n.13 and 55 n. 33. There are two flaws in EOG's argument.

First, EOG's argument is based on the assumption or interpretation that section 78B-2-201 bars suits for royalties due more than seven years before suit is initiated. For the reasons explained above, that is not correct.

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[81] The Utah Court of Appeals explained in *Willis v. DeWitt*, 2015 UT App. 123, 350 P.3d 250, 253 (2015), that a statute of limitations requires a lawsuit to be initiated within a specified period after violation of a legal right, or the judicial remedy is waived. In contrast, a statute of repose "bars all actions after a specified period of time has run from the occurrence of some event other than the occurrence of an injury that gives rise to a cause of action" (quoting *Berry ex rel. Berry v. Beech Aircraft Corp.*, 717 P.2d 670, 672 (Utah 1985)). Once the period specified by a statute of repose has elapsed, "any cause of action is barred regardless of usual reasons for tolling the statute." *Id.*, quoting *Perry v. Pioneer Wholesale Supply Co.*, 681 P.2d 214, 219 (Utah 1984).

[82] Presumably this was because the period to bring an action to establish the State's title runs from the date "the right or title to the property accrued," which is not the date on which an injury (or loss) that gives rise to the right of action occurs.

Second, as quoted above, the new subsection (2) enacted in 2015 states that "[t]he statute of limitations in this section runs from the date on which the state or those from whom it claims received actual notice of the facts giving rise to the action." (Emphasis added.) By enacting subsection (2), the Legislature has expressly specified that section 78B-2-201 is a statute of limitations.

Section 3 of the enacted HB 1001 expressly made the current version of section 78B-2-201 retroactive to March 12, 1953. That necessarily implies that the Legislature has retroactively designated the statute as a statute of limitations since 1953.

IX. EOG's Right to Recoup or Obtain a Refund of Alleged Overpayments

A. Recoupment of Overpayments

In its Petition for Review, EOG said that it had hired an outside party to review its royalty payments for both audit periodsCbased, of course, on assumptions and information given to it by EOG and without review by SITLA or its auditors. EOG asserted that its agent found overpayments totaling approximately $743,000 due to alleged failure to deduct transportation and processing and fuel costs. EOG Petition for Review, p. 5, and Exhibit D. (Exhibit D is referred to hereinafter as the "Ryan Report.") In its opening brief, EOG asserted that it has "found numerous instances where EOG simply failed to take authorized deductions and other instances of duplicate royalty payments for the same gas" and "requests the Board to confirm that it will be allowed a credit or refund for the overpayments. This could easily occur through recoupment or offset of ongoing royalty payments." EOG Opening Brief, p. 11.

It is important to emphasize that at this point, there has been no determination that EOG actually has overpaid. No overpayment has been established as a matter of fact or as a matter of mixed fact and law.[83] Whether a recalculation of royalties due under the legal principles established in this decision—or as those principles may be upheld or modified in any decision on judicial review that may follow—will reveal any overpayments on EOG's part is unknowable at this point. However, the parties disagree on whether EOG may recover or recoup any overpayments it may have made, if any are found.

[83] SITLA is correct in observing that "EOG has not (through the Ryan report or otherwise) provided any backup documentation, or explanatory analysis, relevant to how the alleged $743,000 overpayment was calculated." SITLA Opening Brief, p. 32 n. 12. Beyond the lack of documentation, the Ryan Report presumably is based on EOG's legal position and assumptions regarding deductibility of certain costs, which, for the reasons explained in this analysis, are not correct.

1. The Royalty Due on Production in Each Respective Production Month Is Not a Separate Legal Obligation that Stands Independent of Royalty Due on Gas Produced in Every Other Month.

Addressing these several arguments first requires an analysis of the nature of the royalty interest reserved under the lease and how it relates to the intervals at which the lessee must pay royalty. As quoted above, section 4(b) of all the lease instruments reserves to the State a royalty of 12½ percent of the value of "all gas produced and saved or sold from the leased premises." Section 4(d) of the lease instruments provides: "All royalties on production during any calendar month shall be due and payable by LESSEE to LESSOR not later than the last day of the calendar month following that in which produced."[84] An oil and gas lessee such as EOG, due to any number of causes and while acting in good faith, may end up underpaying in some months and overpaying in other months. Depending on the cause, the lessee may not be aware of either an underpayment or an overpayment during a particular month, or series of months, until months or sometimes years down the road. Reasons may include incorrect production reports or volume measurements that are later corrected, incorrect sales prices that are later corrected, product valuation errors, reporting errors, etc.[85]

SITLA's position in its briefs and in its response to EOG's petition implicitly assumes that the royalty due on gas produced during a particular month is a separate and distinct legal obligation that stands completely independent of, and is unrelated to, royalty due on gas produced in the previous month or in the following month, or the second following month, etc. Nothing in the lease so provides or implies, and SITLA has cited no authority for such a proposition. While royalty must be paid monthly on the gas produced during the month preceding the month of payment, the question posed in an audit is whether royalty on production from the lease during the period under reviewC*e.g.*, the audit periods from 2007 through 2011 and 2012 through 2017 involved in this appealCis underpaid, correct, or overpaid.

SITLA's argument that it may collect underpaid royalties for those production months for which royalty was underpaid but that EOG, at the same time, has no right to recover, recoup, offset, or seek a refund of overpaid royalties for those production months in which royalty was overpaid is a "heads-I-win-tails-you-lose" position that would result in the lessee overpaying royalties over the life of the lease, as well as over any particular audit period. The only way the lessee could avoid that result would be to adopt a policy of deliberately underpaying in every month, and then waiting for the underpayments to be discovered on audit. Such ongoing intentional underpayment would violate the lease terms.

There appears to be no mineral lease case in which SITLA's novel proposition has been applied. If SITLA audits royalty payments under a lease and finds (assuming correct application of law to the facts) that there are overpayments in some months and underpayments in other

[84] By regulation, SITLA has granted lessees an additional month to pay royalty on gas and NGLs. Utah Admin. Code R850-21-500(5). That extra month does not affect the analysis here.

[85] The process of how incorrect payments in earlier months are corrected on the monthly royalty report form, SITLA Form F2221, is discussed below.

months, it has no legal right to demand payments plus interest for the underpaid months and refuse to offset or credit overpayments in other months against amounts due for the underpaid months. There is no legal basis on which SITLA can insist that the lease be maintained in an overpaid status.

2. SITLA's Reliance on the "Voluntary Payment" Doctrine Is Misplaced; Lessees Have an Inherent Right to Recoup Overpayments Resulting from Both Mistakes of Fact and Mistakes of Law.

SITLA, in its response to EOG's petition (at p. 8), maintained that "[u]nder the voluntary payment rule, 'where money has been paid voluntarily with full knowledge of the facts, it cannot be recovered'" (citing *Freston v. Gulf Oil Co.*, 565 P.2d 787, 789 (Utah 1977)). SITLA argues that because EOG knew the character of all the costs it incurred, and does not claim that it relied on a mistake of fact, EOG therefore may not now deduct certain costs that it asserts are costs of transportation or processing. SITLA Reply Brief, p. 16; SITLA Opening Brief, pp. 30-32. EOG maintains that it has a right to recoup any overpaid royalties when royalties due are recalculated, *i.e.*, in the second phase of this appeal. EOG Response Brief, pp. 14-17.

In *Freston v. Gulf Oil Co.*, 565 P.2d 787 (Utah 1977), relied on by both parties, the lessee initially paid royalty for 10 months of production applying an incorrect royalty rate, resulting in a substantial overpayment. The lessee recouped the overpayment by withholding royalties due over several months, then resumed royalty payments at the correct rate. The lessor claimed that the lessee could not recover the overpayments because the lessee had made them voluntarily. In affirming the lower court's rejection of this theory, the Utah Supreme court explained:

> <u>In the absence of a showing of prejudice, equity requires a right of recoupment</u>. . . .
>
> . . . .
>
> In this case, defendant made overpayments by mistake and when the error was noted it promptly advised plaintiffs, withheld future payments until the sum had been recovered, and then began making correct payments. The action of defendant was dictated by equity. It would be highly inequitable to allow plaintiffs to retain something that was not theirs. The identical result was reached in *Gulf Oil Corporation v. Lone Star Producing Co.*[6], wherein the court held that there was no prejudice sustained by reason of the overpayment.
>
> Plaintiffs have not been unduly burdened by defendant's actions since they needed only to wait until the advancements were earned at which time appropriate payments were resumed. <u>The fact that the lease is silent as to recoupment is of no consequence since the right of recoupment is inherent in all contractual matters and is not dependent upon express provisions</u>.

[6] 322 F.2d 28 (5th Cir. 1963).

565 P.2d at 788-789 (emphasis added). In the case cited in *Freston*, *Gulf Oil Corp. v. Lone Star Producing Co.*, 322 F.2d 28 (5th Cir. 1963), Gulf bought oil from Lone Star but overpaid during certain months because it did not deduct the full transportation cost provided for in the contract. The trial court held that Gulf's recoupment of the overpayments was improper on the ground that Gulf had paid the money to Lone Star "voluntarily" and "with full knowledge of all the facts." Reversing this ruling, after acknowledging the general "voluntary payment" principle, the Fifth Circuit held:

> For that principle to apply, however, the overpayments must have been truly voluntary, that is, "done by design or intentionally or purposely or by choice or of one's own accord or by the free exercise of the will." *Prigmore v. Hardware Mutual Ins. Co.*, Tex.Civ.App. 1949, 225 S.W.2d 897, 899. There must appear "an intention on the part of the payor to waive his rights." *West Texas State Bank v. Tri-Service Drilling Co.*, Tex.Civ. App. 1960, 339 S.W.2d 249, 253. *See also*, 40 Am.Jur. Payment, § 159, p. 823; 70 C.J.S. Payment § 134, pp. 343, 344.

322 F.2d at 31 (footnote omitted, emphasis added).

In *City of Carlsbad v. Grace*, 126 N.M. 95, 966 P.2d 1178 (N.M. Ct. App. 1998), the New Mexico Court of Appeals held that a lessee who overpaid royalties over a 16-year period as a result of an accounting error had a right to recoup the overpayments notwithstanding the fact that the applicable statute of limitations barred a lawsuit to recover the overpayments.[86] In 3 Kuntz, *Oil and Gas* (A Revision of Thornton) § 42.8,[87] under the heading "*Effect of mistake in payment of royalty*," the treatise, after noting the general "voluntary payment" principle, explained: "The lessee may, however, recover from the lessor any overpayment of royalty which he made because of mistake of law or fact. A payment by mistake is not a 'voluntary' payment, and it may be recovered even though the payor was negligent in making the payment." (Emphasis added.)

In the context of oil and gas royalties, it is particularly difficult from a logical standpoint to distinguish between good faith mistakes of fact and good faith mistakes of law. Many legal questions governing correct calculation of royaltyCparticularly legal questions involving valuation issuesCmay be unsettled. Indeed, the valuation issues presented in this appeal are prime examples. If royalties are calculated on the basis of a legal premise or assumption

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[86] The court cited, among other cases, the Utah Supreme Court's decision in *Freston*, as well as *Shanbour v. Phillips 66 Natural Gas Co.*, 864 P.2d 815, 817 (Okla. 1993); and *Waechter v. Amoco Production Co.*, 217 Kan. 489, 537 P.2d 228, 253 (1975). *See also* 3 Williams and Meyers, *Oil and Gas Law* § 657 (1997); *Nelson v. Linn Midcontinent Exploration*, 2009 OK Civ. App. 99, 228 P.3d 533 (2009).
[87] Quoted in *Waechter v. Amoco Production Co.*, 217 Kan. at 516.

regarding product valuation made in good faith that the lessee concludes upon further consideration is incorrect, and that ultimately is determined to be incorrect, it would seem to be equally as inequitable to prevent the lessee from recouping the excess royalty payment than it would be in a situation where there has been an accounting error or a volume measurement error. Moreover, preventing lessees from recouping overpayments resulting from mistakes of law very likely would result in more royalty disputes and litigation between lessors (including SITLA) and lessees, because it would create an incentive for lessees to take overly aggressive legal positions on product valuation issues to make certain they avoid overpaying.

Further, allowing recoupment regardless of the category of mistake is more consistent with the nature of the royalty interest discussed above, *i.e.*, that the royalty due on gas produced during a particular month is not a separate discrete legal obligation that is completely independent of or unrelated to royalty on gas produced during every other production month. As noted previously, the question addressed in a multi-year audit is whether royalty on all the production from or allocated to the lease during that time period is underpaid or overpaid, *i.e.*, whether the State as lessor has been paid less than, or more than, the proper royalty on all the production during that time period. If a lease turns out to be net overpaid for an audit period because of a legal error in valuing the production over all or part of that period, the lease is just as much overpaid as it would be if the mistake that resulted in the overpayment was application of an incorrect royalty rate over the same period. It is no more equitable to permit the lessee to recoup the overpayment in the latter situation than in the former. Indeed, it would be inequitable to permit recoupment only in the latter situation and deny it in the former.

Therefore, the right of recoupment that the Utah Supreme Court recognized in *Freston* should apply regardless of the type of mistake that results in an overpayment.

Moreover, in the instant appeal, in the words of the Fifth Circuit in *Gulf Oil Corp. v. Lone Star Producing Co.* (relied on in *Freston*), there is no indication that, if EOG paid more royalty than it owed, it did so "intentionally or purposely." Nor does SITLA contend otherwise. EOG's payments were "voluntary" in the sense that it paid royalty monthly as required under the lease terms without coercive actions or procedures on the part of SITLA or the State to compel it to do so. In that sense, every monthly royalty payment that EOG made was "voluntary." But that does not imply that EOG had any intention to overpay or had purposefully waived its rights to correct erroneous payments or to recover overpayments. While a lessee could intentionally or purposely overpay, there is no indication of such an intent or purpose on EOG's part in the record in this appeal. Nor does the fact that EOG paid its royalties on time imply that the State may simply retain every cent that EOG pays, even if EOG pays more than it owes. The fact that EOG pays on time without coercive action by the State does not operate to prevent it from correcting errors that resulted in overpayments.

Further, if, indeed, EOG overpaid in any particular monthCand we emphasize again that there is no determination that it didCthere has been no allegation or suggestion that there would be any prejudice to SITLA or the State in allowing EOG to correct its payments and recoup whatever amount should not have been paid. As noted previously, the State has no legal right to insist that the lease be maintained in an overpaid status.

Indeed, SITLA's own regulations governing administration of oil and gas leases implicitly acknowledge a lessee's right to recoupment of overpayments. Utah Admin. Code R850-5-300(1)(c), which governs monthly royalty reports, provides in relevant part as follows:

> (c) Any report submitted which includes entries as described below, may not be accepted by the agency and may be returned.
>
> i) Any report submitted 24 months after the royalty due date.
>
> ii) Amendments to prior report periods creating a net adjustment of less than $10.

The monthly royalty report form, SITLA Form F2221, contains 16 columns. The first five of those are headed "1. Amend +/-"; "2. Producing Entity Nbr."; "3. Report Month"; "4. Report Year"; and "5. Product Type". The report month (column 3) may be the current report month or a previous month. The same is true of the report year (column 4). The product type (column 5) specifies oil, gas, etc. The amendment specified in column 1 for an earlier production month may be either an increase (+) or a decrease (-). If a lessee such as EOG reports a decrease for a prior production monthC*i.e.*, a correction to what the lessee believes is an overpayment—the effect of that report line will be to decrease the total payment accompanying the report form. That will effectuate a recoupment of the amount the lessee believes was overpaid.

Further, there is nothing in the SITLA regulation or in the Form F2221 that limits a "minus" correction or amendment to an earlier royalty report (reflecting a correction to an overpayment) to overpayments that are the result of a mistake of fact, or that prohibits corrections to overpayments that result from a mistake of law, or that requires a lessee to specify the reason for the overpayment or adjustment.

Paragraph (1)(c)(i) of the quoted regulation allows SITLA to reject adjusting report lines for months submitted more than two years after the original royalty due date, which in effect would allow SITLA to limit the recoupment period to two years after the original royalty due date for a particular production month. For reasons explained below, it is unnecessary to address that provision here.

In summary, EOG has the inherent right to recoup any overpayments, as the Utah Supreme Court held in *Freston*, even though the lease instrument is silent in that respect. Not allowing EOG to do so would be grossly inequitable.

3. The Cases on which SITLA Relies Are Inapposite.

SITLA relies on *Southern Title Guaranty Co. v. Bethers*, 761 P.2d 951 (Utah Ct. App. 1988), for the proposition that "a person who makes a payment voluntarily, with full knowledge of the facts, and without fraud, duress, or extortion cannot recover back that money even though it was paid without any legal obligation to do so." SITLA Opening Brief, p. 30; s*ee also* SITLA Reply Brief, p. 14. In that case, the holder of a mortgage on a subdivision lot had foreclosed against the party who had purchased the lot from the first purchaser. The mortgage holder then learned that there was a disagreement or uncertainty regarding whether the original seller had been paid for the lot. The mortgage holder then demanded that its title insurer clear the defect in title. After being put on notice of the possibility that the lot already had been paid for, the title insurer nevertheless paid the price of the lot to the original seller and obtained a conveyance that cleared the title, without any reservations or protest or further investigation. The court therefore rejected the title insurer's claim against the original seller for unjust enrichment. This situation has no real relevance here, where there is an ongoing relationship of continuous payments by a mineral lessee to the lessor at defined intervals and in different amounts for ongoing production, where the calculation of the payments depends upon often complex and potentially changing information, and where subsequent corrections to many of those payments almost inevitably will be necessary.

SITLA also relies on *Nevada Association Services, Inc. v. Eighth Judicial District Court*, 130 Nev. Adv. Op. 94, 338 P.3d 1250 (Nev. 2015). SITLA cites this case for the proposition that "[a] contractual obligation to make a payment does not constitute duress, even if a failure to pay may lead to contract termination or other remedies, if the paying party has alternatives to payment." SITLA Opening Brief, p. 31. First, EOG has never asserted that its royalty payments were made under duress and for that reason were not "voluntary." But the fact that royalty payments are not made under "duress" does not imply that overpayments were made voluntarily, in the sense of deliberately or intentionally.

Second, the statement from the court's opinion regarding duress and contractual obligations to make payments that SITLA quotes, though it appears to be an accurate statement of general principle, is *dicta*. *Nevada Association Services* did not involve a contractual obligation to make a payment, much less a situation in which a mineral lessee is making regular periodic payments. It involved a one-time payment to pay off a lien to remove an encumbrance to title and enable a purchaser to resell a parcel of real property, when the obligation to make the payment was disputed at the time of payment.

SITLA further quotes *Martin v. Hickenlooper*, 90 Utah 150, 59 P.2d 1139, 1144 (1936), for the proposition that "a mistake of fact is a mistake not caused by the neglect of a legal duty on the part of the person making the mistake" and that a party "who fails, through culpable inertness, to make inquiry when it is his duty to inquire, and by reason of such failure loses a valuable right, is not entitled to relief in equity on the ground of mistake." SITLA Reply Brief, p. 16. For the reasons explained above, the Board disagrees that recoupment of royalty overpayments is limited to overpayments resulting from mistakes of fact. We note that *Martin v. Hickenlooper* did not involve a situation analogous to oil and gas royalties. It involved application of subrogation principles in the context of multiple mortgages on a parcel of real property.

In short, the cases on which SITLA relies are inapposite.

4. The Cases on which EOG Relies Are Inapposite.

EOG, for its part, quotes the statement in *State Farm Mutual v. Northwestern National Insurance Co.*, 912 P.2d 983, 986 (Utah 1996), that "[a] payment is not voluntary if it is made with a reasonable or good faith belief in an obligation or personal interest in making that payment." EOG Opening Brief, p. 12. *State Farm Mutual*, however, is not a "voluntary payment doctrine" case. It addressed whether a payment made by an insurer of an individual to settle a claim was "voluntary" in the context of whether the individual's insurer had a valid subrogation claim against the insurer of the individual's employer. Thus, *State Farm Mutual* is inapposite.

EOG cites *Hull v. Freeman*, 383 S.W.2d 236 (Tex. Civ. App. 1964), and *Kirby McInerney & Squire, LLP v. Hall Charne Bruce & Olson, S.C.*, 15 A.D.3d 233,790 N.Y.S. 2d 84 (N.Y. App. Div. 2005), for the principle that overpayments based on a mistake of fact may be recovered or recouped because a mistake of fact is an exception to the voluntary payment doctrine. EOG suggests that any miscalculation of amounts owed is a mistake of fact. EOG Opening Brief at 12-13. The mistake in *Hull* was applying an incorrect overriding royalty rate to volumes that were below the threshold that triggered a lower royalty rate. In *Kirby, McInerney & Squire*, the mistake was in the amount of professional fees owed. These cases do not imply that any miscalculation for any reason constitutes a mistake of fact. But it is not necessary for EOG to try to recategorize all mistakes of law into mistakes of fact. For the reasons explained above, EOG has a right to recoup overpayments regardless of whether the overpayments resulted from a mistake of fact or a mistake of law.

B. Offset of Overpayments and Underpayments Made in Different Months During the Audit Period

EOG's legal right to recoup overpayments (if there were overpayments) will come into play for the time periods involved in this appeal after the second phase of the appeal is concluded, *i.e.*, after EOG and SITLA have recalculated royalties under the legal principles established in this decision (or as this decision may be modified in the course of judicial review). In the course of that recalculation, any overpayments in overpaid months must be offset against underpayments in underpaid months for each lease to determine whether royalty has been underpaid or overpaid for that lease during the audit period. Should it turn out that a lease is net overpaid, EOG may properly recoup the overpaid amount.

For that reason, it is unnecessary in this appeal to address Utah Admin. Code R850-5-300(1)(c)(i), which allows SITLA to reject adjusting report lines submitted more than two years after the royalty due date. If a lease is determined to be net overpaid after all overpayments and underpayments during the audit period have been offset, EOG can submit one adjustment line for the current month for which reports are due to effectuate the final audit result and recoup the overpaid amount. Because the audit for the period ~~July~~ January 2007 through December 2011 had not been resolved and the issues arising from that audit are the subject of this appeal and continue through the subsequent audit for the 2012 through 2017 period, the two audit periods involved in this appeal effectively have been combined. Thus, the audit period referred to here is the entire period from ~~July~~ January 2007 through December 2017.

If a lease is net underpaid after all overpayments and underpayments during the audit period have been offset, interest at the rate prescribed under applicable law or regulation (*see* Utah Admin. Code R850-5-300(2)) should be assessed on the amount by which the lease was underpaid, beginning when the lease became net underpaid and remained net underpaid from that time through the end of the ~~July~~ January 2007 through December 2017 audit period, until the amounts owing are paid.

C. EOG's Right to a Refund of Overpayments or to Recover Overpayments Through a Judicial Lawsuit

SITLA appears to argue, at least implicitly, that if EOG could not successfully maintain a cause of action in a judicial lawsuit for a refund of overpayments, if there are any, then it may not recoup overpayments. SITLA argues that EOG cannot successfully maintain any cause of action to recover overpayments. SITLA Opening Brief, pp. 29-30; SITLA Reply Brief, pp. 11-13.

SITLA's apparent conceptual framework is inconsistent with the Utah Supreme Court's decision in *Freston*. The equitable right of an oil and gas lessee to recoup overpayments recognized in *Freston* and other cases in other states is not contingent or dependent upon a lessee also being able to recover overpayments through judicial litigation. The lessee's right to recoup overpayments on its own initiative may still apply even if a judicial lawsuit to recover overpayments would or may be barredCfor example, if a lawsuit would be time-barred under an applicable statute of limitations, as the New Mexico and Kansas courts, respectively, recognized in *City of Carlsbad v. Grace*, *supra*, and *Waechter v. Amoco Production Co.*, *supra* (*see* 214 Kan. at 517-521).

SITLA argues that "*Freston* did not recognize a distinct cause of action for recoupment." SITLA Reply Brief, p. 12. This argument has it backwards. The right to recoup overpayments recognized in *Freston* does not depend on asserting a particular "cause of action" in a judicial proceeding. *Freston* recognizes that a lessee who has overpaid may recoup without resorting to judicial process.

Nevertheless, if recoupment of overpayments, if there were any, for some reason turns out to be not practicable or possibleCor even if SITLA's conceptual framework were acceptedCSITLA's arguments that EOG could not maintain a cause of action to recover overpayments in a lawsuit are flawed and are not persuasive.

1. Contractual Right to Refund/Unjust Enrichment

SITLA argues that EOG has no contractual right under the lease instruments to recover overpaid royalties. SITLA Opening Brief, p. 30; *see also* SITLA Reply Brief, p. 12. SITLA is correct that the lease instruments themselves do not include an express right to a refund of overpayments. But that does not mean that EOG has no right of action to recover overpayments.

In *CIG Exploration, Inc. v. State*, 2001 UT 37, 24 P.3d 966 (2001) (cited in EOG Opening Brief, p. 12), an oil and gas lessee sued the State to recover overpaid royalties where the overpayment resulted from the lessee having charged a higher price than allowed under the NGPA, as determined by the Federal Energy Regulatory Commission (FERC). The lessee had paid royalty based on the higher price, and sought to recover the difference between what it had paid and what should have been paid based on the lower allowed sale price. CIG pled its claim as one under "federal common law" for reimbursement based on "justice and fairness" and not as a claim under the lease.

The issue was whether the 4-year statute of limitations for actions on obligations or liabilities not founded upon an instrument in writing at former Utah Code Ann. § 78-12-25(1) (now section 78B-2-307(1)) applied and barred CIG's lawsuit. The Utah Supreme Court held that "CIGE's cause of action to recover the alleged excess royalty payments was for monies had and received" and not for breach of an implied covenant of the lease. 24 P.3d at 971. Consequently, the 4-year statute applied.

It is implicit in the Utah Supreme Court's ruling that a lessee may sue to recover excess royalty payments. SITLA correctly notes that a claim for "money had and received," which is a claim under a contract implied in law, is another term for a claim for unjust enrichment. SITLA Reply Brief, p. 13, citing *Jones v. Mackey Price Thompson & Ostler*, 2015 UT 60, 355 P.3d 1000, 1012 (2015). SITLA correctly states that the elements of a claim for unjust enrichment, or a claim under a contract implied in law, are "'(1) a benefit conferred on one person by another; (2) an appreciation or knowledge by the conferee of the benefit; and (3) the acceptance or retention by the conferee of the benefit under such circumstances as to make it inequitable for the conferee to retain the benefit without payment of its value.'" SITLA Reply Brief , p. 13.[88]

SITLA maintains that EOG "has not asserted facts or provided evidence to support an unjust enrichment claim[.]" SITLA Reply Brief, p. 13. If one or more of EOG's leases actually is overpaid, the first elementCconferral of a benefitCobviously is satisfied. Addressing the second element—knowledge of the benefit by the recipient—SITLA argues that it "had no knowledge that any of EOG's royalty payments were allegedly excessive at the time they were made." *Id*. To meet the second element, however, it is not a legal requirement that a defendant be specifically aware of a benefit contemporaneously with receiving it. When an oil and gas lessee reports a correction to an overpayment in an earlier month or makes a claim for a refund, SITLA certainly acquires knowledge of the benefit (the claimed overpayment) at that time, and the lessor can then ascertain whether it agrees that it has been overpaid. SITLA also argues that it "has not misled EOG in any way, committed fraud, or taken any action that would justify an unjust enrichment claim." *Id*. However, a misleading or fraudulent action on the part of the recipient of a benefit is not an element of an unjust enrichment claim.

SITLA fails to address the third element, *i.e.*, that the defendant retain or receive a benefit under circumstances that make it inequitable to retain the benefit without paying for it. If one or more of EOG's leases actually is overpaid, it would be highly inequitable for the State to retain the overpaymentCprecisely the point the Utah Supreme Court made in *Freston*. It thus would appear that a claim for refund or recovery of royalty overpayments would satisfy all elements of a claim for unjust enrichment.

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[88] Quoting *Richards v. Brown*, 222 P.3d 69, 78 (Utah Ct. App. 2009). *See also*, *Jones v. Mackey Price Thompson & Ostler*, *supra*, 355 P.3d at 1012; *Emergency Physicians Integrated Care v. Salt Lake County*, 2007 UT 72, 167 P.3d 1080, 1083 (2007).

2. "Failure to Exhaust" Administrative Remedies

SITLA argues that any EOG claim for refund is barred because of EOG's alleged "failure to exhaust its available legal remedies." SITLA relies on the Utah Supreme Court's decision in *Bivens v. Salt Lake City Corp.*, 2017 UT 67, 416 P.3d 338 (2017). SITLA Reply Brief, pp. 11-12. SITLA maintains that the available procedure to amend prior months' royalty reports discussed above constitutes a required administrative remedy that falls within the requirement to exhaust administrative remedies before pursuing judicial relief. Because Utah Admin. Code R850-5-300(1)(c)(i) allows SITLA to reject adjusting report lines submitted more than two years after the royalty due date, and EOG asserts that it made overpayments for periods more than two years ago, SITLA argues, in substance, that EOG may not now seek a refund of any overpayments it may have made more than two years ago. *Id*.

SITLA's argument and its reliance on *Bivens* are misplaced. The requirement to exhaust administrative remedies comes into play when an agency of the State has taken some action against a person or party who is challenging the legality or propriety of that action. The exhaustion doctrine requires the party to first seek relief through an available administrative process before challenging the State's action in court.[89] EOG is pursuing available administrative remedies to challenge SITLA's audit determinations <u>in the instant appeal</u>. The fact that royalty payors under State leases can adjust previously submitted reports for earlier production months and either pay additional royalties or recoup prior overpayments is not a procedure for challenging the legality or propriety of an action taken by the State agency (SITLA), and is not the type of administrative remedy the exhaustion doctrine contemplates. It is a procedure that the royalty payor undertakes on its own initiative, without any action by SITLA which the payor is challenging.

In addition, if a royalty payor discovers or determines that it made errors that resulted in overpayments more than two years previously, the payor may have no choice other than to seek a refund through judicial proceedings if it does not want to wait for an audit to be performed, unless SITLA were to agree to permit the payor to recoup through the established adjustment process. SITLA's argument that a judicial lawsuit to recover the overpayments would be barred if the agency did not agree to such a recoupment amounts to an attempt to administratively impose a statute of limitations on a judicial proceeding. While that is not an issue before this Board, imposing a statute of limitations on a judicial action by administrative rule is obviously not within SITLA's power or authority. Enacting statutes of limitation is the province of the legislature (as the Utah Supreme Court noted in *State v. Rettig*, 2017 UT 83, 416 P.3d 520, 531 n. 13 (2017)).

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[89] *Bivens* is an example of this. In that case, the plaintiffs challenged the legality of Salt Lake City parking tickets in court after failing to challenge them through the established administrative process.

3. "Failure to State a Claim"

In its opening brief, SITLA argued:

> SITLA asks the Board to dismiss EOG's request for a refund of past royalties because EOG has failed to state a claim upon which relief can be granted. SITLA's rules require that a petition for adjudicative proceedings "state . . . any statute, rule, contract provision, or board policy which the final agency action is alleged to violate." Utah Admin. Code, R850-8-1000; *see also* Utah Code § 63G-4-201(3)(a). "A complaint states a claim upon which relief can be granted if it alleges the facts and sets forth the legal basis for an available legal remedy." *Rusk v. University of Utah Healthcare Risk Management*, 391 P.3d 325, 326 (UT App 2016) (internal citations omitted).

SITLA Opening Brief, pp. 28-29. This argument is misplaced. Failure to state a claim upon which relief can be granted is an affirmative defense to a claim for relief in a civil lawsuit and a ground for dismissal of lawsuit under Rule 12(b)(6) of the Utah Rules of Civil Procedure. As stated in the excerpt from the Utah Court of Appeals' decision in *Rusk v. University of Utah Healthcare Risk Management* that SITLA quotes, a <u>complaint</u> states a claim upon which relief may be granted if it sets forth the legal basis for an available legal remedy. EOG's petition is not a complaint that initiates a lawsuit under Rule 3(a) of the Utah Rules of Civil Procedure. The affirmative defense of failure to state a claim has no application in the context of an administrative appeal.

EOG's petition meets the requirement of Utah Admin. Code R850-8-1000(2)(B)(ii) to state "any statute, rule, contract provision, or board policy which the final agency action is alleged to violate[.]" The petition alleges a number of legal errors in the SITLA audit findings, which are explained more fully in EOG's briefs and which give rise to the issues presented in this appeal.

4. Governmental Immunity

In its response to EOG's petition (at p. 8), SITLA asserted that "EOG's refund claim, and the present assertion of that claim within the context of this appeal, are barred by the provisions of the Governmental Immunity Act of Utah, Utah Code §§ 63G-7-101 *et seq*." EOG countered in its opening brief that "[w]hether recoupment, monies had and paid, or offset are considered contractual or equitable claims, these methods of recovery are not barred by the UGIA [*sic*]." EOG Opening Brief, p. 13.

The Governmental Immunity Act of Utah (GIAU) provides at § 67G-7-301(1), Utah Code Ann., in relevant part:

> (1)(a) Immunity from suit of each governmental entity is waived as to any contractual obligation.
>
> (b) Actions arising out of contractual rights or obligations are not subject to the requirements of Section 63G-7-401, 63G-7-402, 63G-7-403, or 63G-7-601 [the statutory notice and initiation requirements].

First, this provision does not apply to recoupment of past overpayments through offset against royalty payments currently due. By its terms, it applies to lawsuits.

Second, with regard to lawsuits to recover overpaid royalties, the Utah courts, as explained above, have held that claims for overpaid royalties are claims for unjust enrichment. Claims for unjust enrichment are equitable in nature. The GIAU and its predecessors do not bar equitable claims. *American Tierra v. City of West Jordan*, 840 P.2d 757, 759 (Utah 1992), and cases cited.[90]

For these reasons, the GIAU does not prevent EOG from recovering past overpayments in these proceedings.

~~FINAL~~ INTERIM ORDER

On the basis of the foregoing Findings of Fact, Conclusions of Law, and Legal Analysis, the Board hereby modifies the royalty assessments in SITLA's 2012 Audit Report and 2018 Audit Report as follows:

1. The assessments for the amounts and estimated amounts of royalties and interest due in both the 2012 Audit Report and the 2018 Audit Report are set aside.

2. The parties are ordered to recompute royalties and interest due on gas produced from or allocated to the subject leases for the period ~~July 1,~~ January of 2007, through December 31, 2017, consistent with the Conclusions of Law set forth above and the supporting Legal Analysis.

3. Pursuant to Rule R850-8-1500.2, and the January 9, 2019 Order Appointing Geoffrey Heath as Hearing Examiner, the Hearing Examiner is empowered to manage, and to the extent it aids progress in this matter, referee and issue interim recommendations concerning, the recalculation phase of this case as referenced in paragraph 2, above. The Hearing Examiner is further directed to work with the parties to develop a schedule for the recalculation phase of the proceedings that expedites, to the extent practical, resolution of this matter. The schedule should

[90] As noted previously, the lease instruments themselves do not include an express right to a refund of overpayments. For this reason, EOG's citation to the Utah Supreme Court's *dictum* in *Patterson v. American Fork City*, 2003 UT 7, & 13, 67 P.3d 466, 470 (Utah 2003), that "the UGIA does not bar 'actions arising out of contractual rights,' and UGIA notice requirements simply do not apply to breach of contract suits against the state" (EOG Opening Brief, p. 13) is inapposite.

contemplate submission of the remaining dispute to the Hearing Examiner for decision within 90 days or such other time frame as the parties may determine is appropriate.

~~An aggrieved party to this Final Order may obtain judicial review in the Utah Court of Appeals under Utah Code Ann. §§ 53C-1-304(5), 63G-4-401, and 63G-4-403, and Utah Admin. Code R850-8-1800 and R850-8-1900.~~

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DATED this ______ day of _________________________, 2021.

UTAH SCHOOL AND INSTITUTIONAL TRUST LANDS ADMINISTRATION BOARD OF TRUSTEES

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Seep Ridge & Holliday Block OBA (Oil & Gas) – Amend & Replace

BOARD MEMORANDUM

DATE: June 7, 2021

TO: Board of Trustees, Utah School & Institutional Trust Lands Administration (SITLA)

FROM: Wesley Adams, Assistant Director – Oil & Gas

RE: Seep Ridge and Holliday Block OBAs (ML-90017 & ML-90016)

LANDS PROPOSED:

24,377 acres, more or less
Seep Ridge Block and Holliday Block
Uintah County, Utah
See Attached Maps

FUND: School 100%

APPLICANT:
Morning Gun Exploration, LLC
1601 Arapahoe Street Box 1
Denver, CO 80202

REQUIREMENT
As provided for under Utah Code Annotated 53C-2-401(1)(d)(ii), which permits the SITLA Board of Trustees to approve "Other Business Arrangements" (OBA), Morning Gun Exploration (MGE) and Great Northern Gas Company (GNG) submitted a proposal for SITLA Oil, Gas and Associated Hydrocarbons leases on February 25, 2021.

This proposed amended OBA was reviewed by the SITLA Board Mineral Committee on June 3, 2021. The committee has provided a recommendation for approval before the full Board of Trustees on June 17, 2021.

PROPOSAL
MGE and GNG would like to establish a new OBA covering both Seep Ridge and Holliday Blocks on September 1, 2021 – leases and present OBA's remaining in effect until such time as the new OBAs take effect.

1. **Seep Ridge Block:**
    a. $8/acre for the Seep Ridge Block, ($85,974 payable on or before August 30, 2021) for 3-year paid up leases with a single vertical well commitment.

    b. The vertical well commitment will be drilled to a depth deep enough to penetrate 100' into the Mancos B. Data acquired in the test well will be provided to SITLA and remain held confidential for a period one year or in accordance with UDOGM confidential status.

c. If the initial test well is drilled and completed, or plugged and abandoned according to state regulations, within the 3-year term, the leases shall be extended for 2 additional years with the payment.

d. If science from the vertical well supports a horizontal well, operator will kick-off from the existing vertical, or drill a new horizontal to test the viability of the Mancos B within the 2-year extended term.

2. **Holliday Block:**
   a. $2/acre ($27,581 paid annually, beginning on or before August 30th, 2021), for 5-year term beginning September 1, 2021.

   b. Should a vertical well not be drilled within the 3-year term, the leases of both Seep Ridge and Holliday block will expire on under their own terms and the OBA's will expire under their own terms.

3. **State Exploratory Unit:**
   a. Should the operator successfully drill the vertical commitment well within the 3-year term, during the remaining 2 years the operator shall have the exclusive right to negotiate a State Exploratory Unit with SITLA, covering both the Seep Ridge and Holliday Block, subject to a mutually agreed upon Plan of Development negotiated with and approved by SITLA.

   b. Should a new horizontal, or lateral kick-off be drilled and completed, or plugged and abandoned according to state regulations, within the 3-year term, or remaining 2-year term, the operator shall have the exclusive right to negotiate a State Exploratory Unit with SITLA, covering both the Seep Ridge and Holliday Block, subject to a mutually agreed upon Plan of Development negotiated with and approved by SITLA.

RECOMMENDATION

SITLA's Oil & Gas team reviewed MGA and GNG's proposal and recommend the SITLA Board of Trustees grant approval to Amend and Restate existing OBAs as outlined below in key points.

1. **Seep Ridge Block, ML-90017 OBA:**
   a. Amend existing leases, effective September 1, 2021, extending the primary terms three (3) years from September 1, 2021, with a paid-up bonus of $8/acre ($85,974), payable on or before August 31, 2021. The royalty will remain at 17%, no annual rentals.

   b. A vertical test well (well) to be drill to a depth deep enough to penetrate 100' into the Mancos B. If the well is drilled and completed within the three (3) year term, the leases shall be extended for two (2) additional years with a renewed paid-up bonus of $4/acre ($42,987).

   c. All data acquired in the well(s) will be provided to SITLA and remain confidential for a period of one year or in accordance with UDOGM confidential status.

   d. If a well is not drilled on these lands or the Seep Ridge Block lands, this agreement and associated leases will expire August 31, 2024.

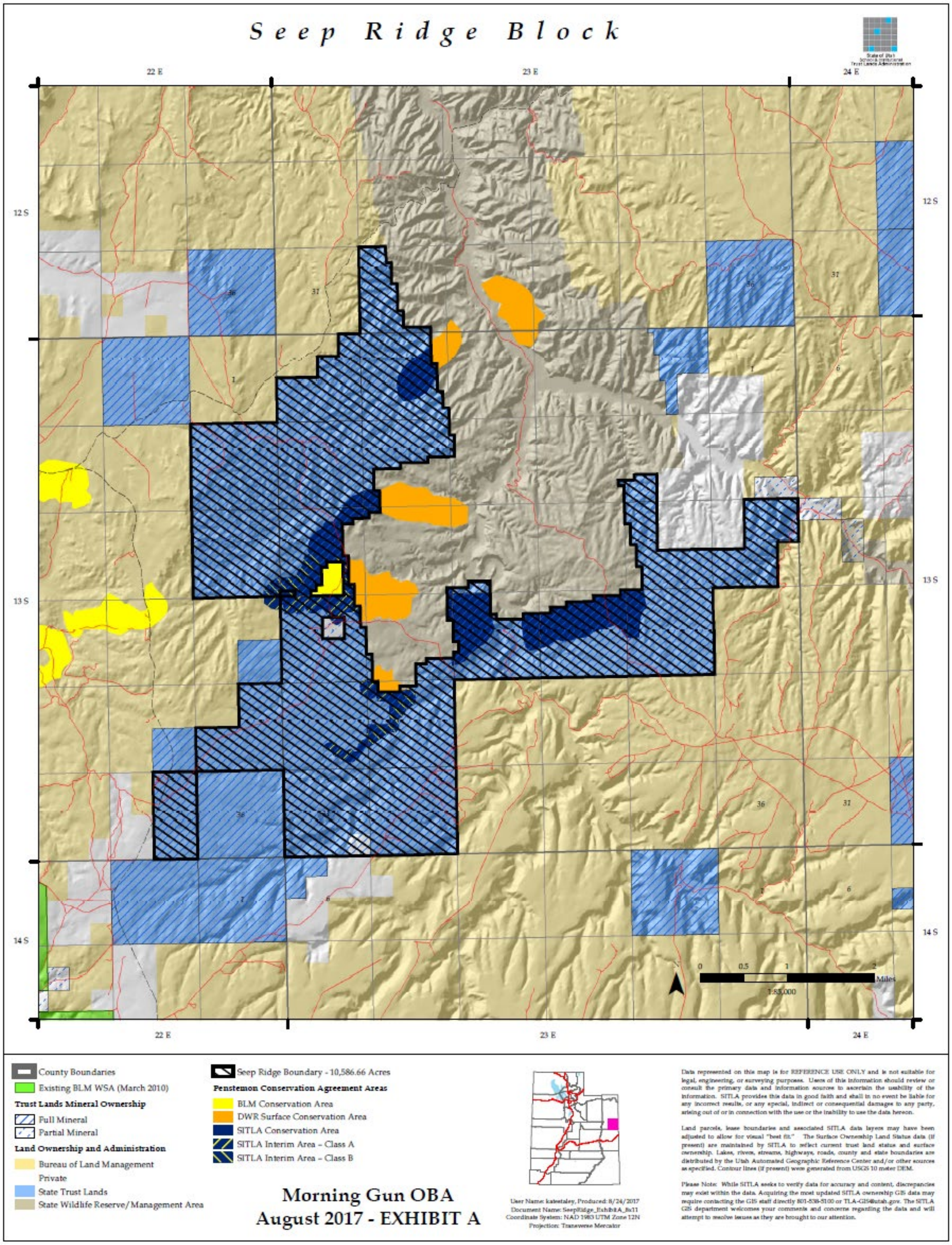
2. **Holliday Block, ML-90016 OBA:**
    a. Amend existing leases, effective September 1, 2021, extending the primary terms five (5) years. The royalty will remain at 17% and annual rentals will remain at $2/acre ($27,581). An annual rental payable on or before August 31, 2021.

    b. If a well is not drilled on these lands or the Seep Ridge Block lands, this agreement and associated leases will expire August 31, 2024.

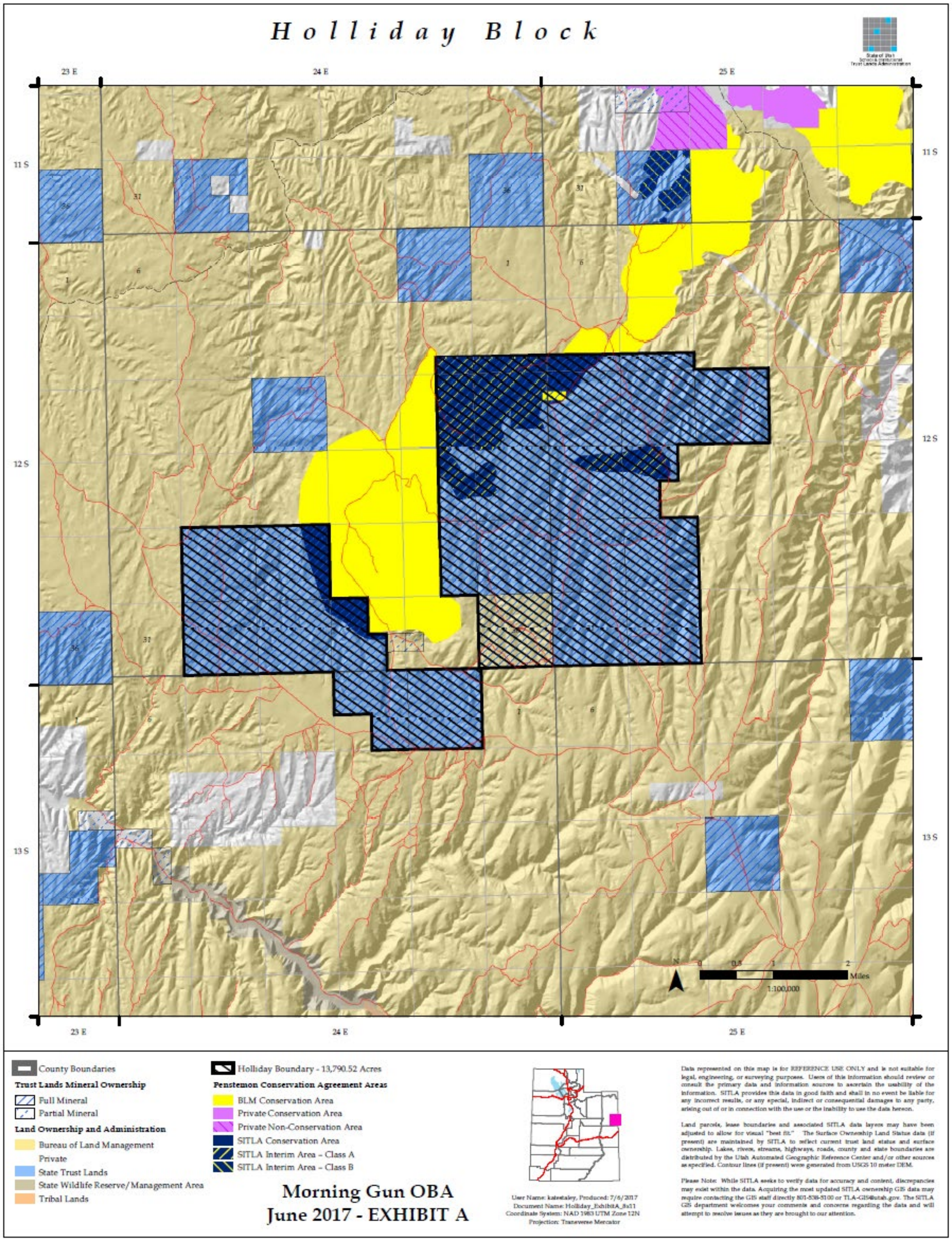
3. **State Exploratory Agreement:**
    a. Upon drilling a well, MGE and GNG or its successors and assigns will earn the right to negotiate a State Exploratory Agreement with SITLA. Said agreement will constitute a good faith intent to explore both Seep Ridge and Holliday Block leases in a timely manner beyond September 1, 2026, with a reasonable drilling commitment and Plan of Development to justify leasehold thereunder.

Respectfully submitted,

Wes Adams
Assistant Director – Oil & Gas



Seep Ridge Block
22 E
23 E
24 E
12 S
13 S
14 S
0
0.5
1
2
Miles
1:85,000
County Boundaries
Existing BLM WSA (March 2010)
Trust Lands Mineral Ownership
Full Mineral
Partial Mineral
Land Ownership and Administration
Bureau of Land Management
Private
State Trust Lands
State Wildlife Reserve/Management Area
Seep Ridge Boundary - 10,586.66 Acres
Penstemon Conservation Agreement Areas
BLM Conservation Area
DWR Surface Conservation Area
SITLA Conservation Area
SITLA Interim Area – Class A
SITLA Interim Area – Class B
Morning Gun OBA
August 2017 - EXHIBIT A
User Name: katestaley, Produced: 8/24/2017
Document Name: SeepRidge_ExhibitA_8x11
Coordinate System: NAD 1983 UTM Zone 12N
Projection: Transverse Mercator
Data represented on this map is for REFERENCE USE ONLY and is not suitable for legal, engineering, or surveying purposes. Users of this information should review or consult the primary data and information sources to ascertain the usability of the information. SITLA provides this data in good faith and shall in no event be liable for any incorrect results, or any special, indirect or consequential damages to any party, arising out of or in connection with the use or the inability to use the data hereon.
Land parcels, lease boundaries and associated SITLA data layers may have been adjusted to allow for visual "best fit." The Surface Ownership Land Status data (if present) are maintained by SITLA to reflect current trust land status and surface ownership. Lakes, rivers, streams, highways, roads, county and state boundaries are distributed by the Utah Automated Geographic Reference Center and/or other sources as specified. Contour lines (if present) were generated from USGS 10 meter DEM.
Please Note: While SITLA seeks to verify data for accuracy and content, discrepancies may exist within the data. Acquiring the most updated SITLA ownership GIS data may require contacting the GIS staff directly 801-538-5100 or TLA-GIS@utah.gov. The SITLA GIS department welcomes your comments and concerns regarding the data and will attempt to resolve issues as they are brought to our attention.



Holliday Block
State of Utah School & Institutional Trust Lands Administration
23 E
24 E
25 E
11 S
12 S
13 S
Miles
1:100,000
County Boundaries
Trust Lands Mineral Ownership
Full Mineral
Partial Mineral
Land Ownership and Administration
Bureau of Land Management
Private
State Trust Lands
State Wildlife Reserve/Management Area
Tribal Lands
Holliday Boundary - 13,790.52 Acres
Penstemon Conservation Agreement Areas
BLM Conservation Area
Private Conservation Area
Private Non-Conservation Area
SITLA Conservation Area
SITLA Interim Area - Class A
SITLA Interim Area - Class B
Morning Gun OBA
June 2017 - EXHIBIT A
User Name: katestaley, Produced: 7/6/2017
Document Name: Holliday_ExhibitA_8x11
Coordinate System: NAD 1983 UTM Zone 12N
Projection: Transverse Mercator
Data represented on this map is for REFERENCE USE ONLY and is not suitable for legal, engineering, or surveying purposes. Users of this information should review or consult the primary data and information sources to ascertain the usability of the information. SITLA provides this data in good faith and shall in no event be liable for any incorrect results, or any special, indirect or consequential damages to any party, arising out of or in connection with the use or the inability to use the data hereon.
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10f

Montezuma

Creek OBA

(Helium)

BOARD MEMORANDUM

DATE: June 7, 2021

TO: Board of Trustees, Utah School & Institutional Trust Lands Administration (SITLA)

FROM: Wesley Adams, Assistant Director – Oil & Gas

RE: Montezuma Creek OBA; San Juan County, UT.

LANDS PROPOSED:

San Juan County, UT

14,672 Acres (shown on attached Exhibit Map)

FUND: School 88.18%
University of Utah 1.8%
NS 5.72%
School of Mines 4.3%

APPLICANT:
RCS Resources, LLC
Attn: Steve Smith
509 Woodvale Ave.
Lafayette, LA 70503

REQUIREMENT
As provided for under Utah Code Annotated 53C-2-401(1)(d)(ii), which permits the SITLA Board of Trustees to approve "Other Business Arrangements" (OBA), RCS Resources, LLC (RCS) submitted a proposal to SITLA for leases covering helium, oil, gas and associated hydrocarbons on May 13, 2021.

This proposed OBA was reviewed by the SITLA Board Mineral Committee on June 3, 2021. The committee has provided a recommendation for approval before the full Board of Trustees on June 17, 2021.

PROPOSAL

RCS is proposing a helium-based exploration concept that will establish leases for scattered sections with an initial lease term of 2-years at $5/ acre bonus and carry the option of an additional 3-years, if one exploratory well is dilled within the initial 2-year terms under a plan of development, aiming for Q4 of 2021 or Q2 of 2022. RCS requests confidentiality on all proprietary information shared with SITLA regarding this OBA.

RECOMMENDATION
The SITLA Oil & Gas team reviewed RCS's proposal and recommends that the SITLA Board of Trustees grant approval to issue an OBA as outlined below in key points:

1. Issue new leases to RCS covering 14,672 acres, effective July 1, 2021, with 2-year initial primary terms. Royalty of 12.5% with no post-production costs and $2/ acre annual rentals. Leases will have an option to extend primary terms for 3-years if a test well is drilled during the initial 2-years terms.

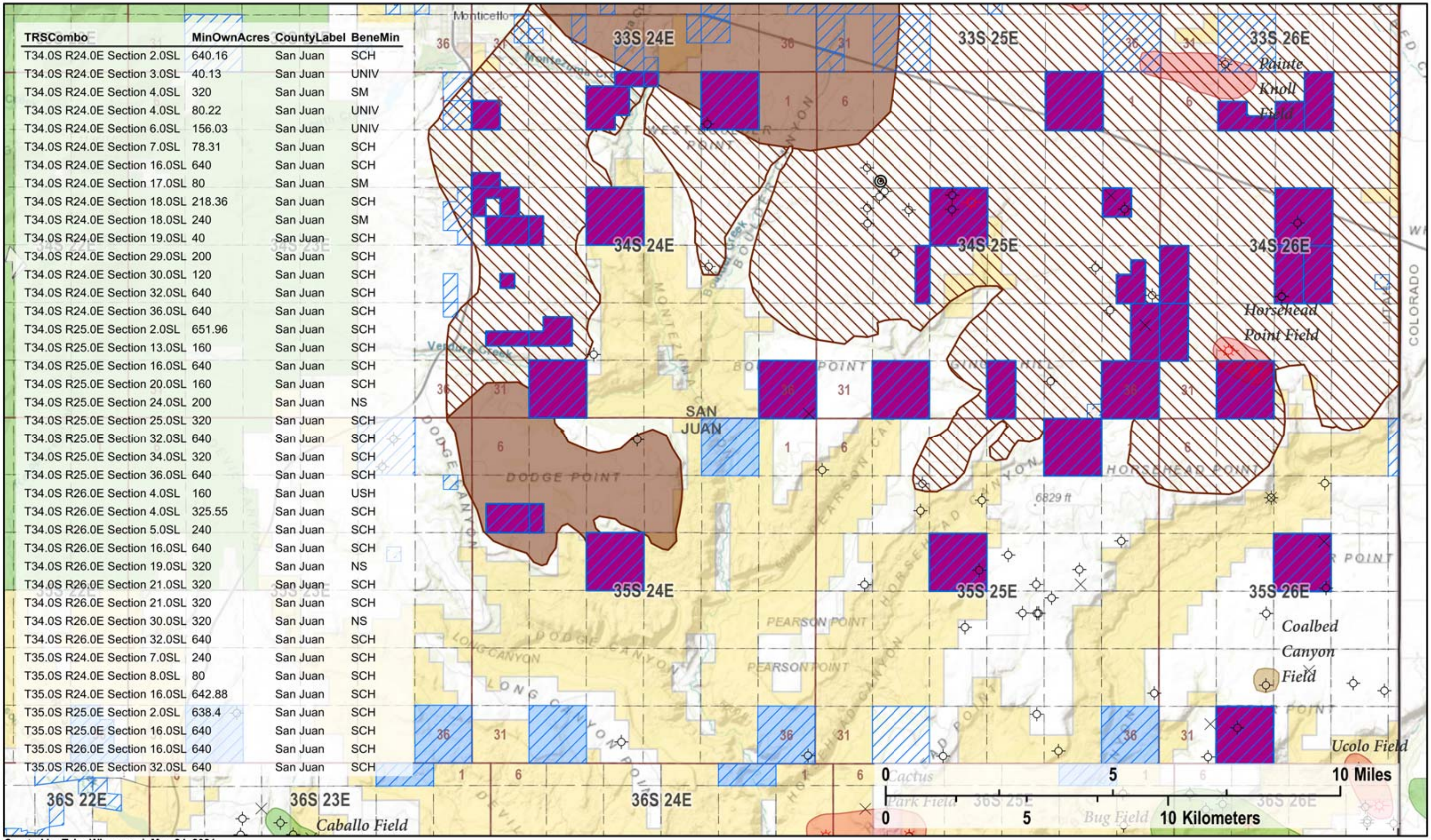
2. Bonus payment of $5/ acre.

3. RCS must complete the drilling of a test well within the original 2-year primary terms or all leases will expire and the end of year 2, as will the 3-year option to extend primary terms.

4. SITLA has the right to review scientific data collected under leases earned in this OBA upon request, including information that may be held confidential for proprietary reasons or interpretive risk.

Respectfully submitted,

Wes Adams
Assistant Director – Oil & Gas



TRSCombo	MinOwnAcres	CountyLabel	BeneMin
T34.0S R24.0E Section 2.0SL	640.16	San Juan	SCH
T34.0S R24.0E Section 3.0SL	40.13	San Juan	UNIV
T34.0S R24.0E Section 4.0SL	320	San Juan	SM
T34.0S R24.0E Section 4.0SL	80.22	San Juan	UNIV
T34.0S R24.0E Section 6.0SL	156.03	San Juan	UNIV
T34.0S R24.0E Section 7.0SL	78.31	San Juan	SCH
T34.0S R24.0E Section 16.0SL	640	San Juan	SCH
T34.0S R24.0E Section 17.0SL	80	San Juan	SM
T34.0S R24.0E Section 18.0SL	218.36	San Juan	SCH
T34.0S R24.0E Section 18.0SL	240	San Juan	SM
T34.0S R24.0E Section 19.0SL	40	San Juan	SCH
T34.0S R24.0E Section 29.0SL	200	San Juan	SCH
T34.0S R24.0E Section 30.0SL	120	San Juan	SCH
T34.0S R24.0E Section 32.0SL	640	San Juan	SCH
T34.0S R24.0E Section 36.0SL	640	San Juan	SCH
T34.0S R25.0E Section 2.0SL	651.96	San Juan	SCH
T34.0S R25.0E Section 13.0SL	160	San Juan	SCH
T34.0S R25.0E Section 16.0SL	640	San Juan	SCH
T34.0S R25.0E Section 20.0SL	160	San Juan	SCH
T34.0S R25.0E Section 24.0SL	200	San Juan	NS
T34.0S R25.0E Section 25.0SL	320	San Juan	SCH
T34.0S R25.0E Section 32.0SL	640	San Juan	SCH
T34.0S R25.0E Section 34.0SL	320	San Juan	SCH
T34.0S R25.0E Section 36.0SL	640	San Juan	SCH
T34.0S R26.0E Section 4.0SL	160	San Juan	USH
T34.0S R26.0E Section 4.0SL	325.55	San Juan	SCH
T34.0S R26.0E Section 5.0SL	240	San Juan	SCH
T34.0S R26.0E Section 16.0SL	640	San Juan	SCH
T34.0S R26.0E Section 19.0SL	320	San Juan	NS
T34.0S R26.0E Section 21.0SL	320	San Juan	SCH
T34.0S R26.0E Section 21.0SL	320	San Juan	SCH
T34.0S R26.0E Section 30.0SL	320	San Juan	NS
T34.0S R26.0E Section 32.0SL	640	San Juan	SCH
T35.0S R24.0E Section 7.0SL	240	San Juan	SCH
T35.0S R24.0E Section 8.0SL	80	San Juan	SCH
T35.0S R24.0E Section 16.0SL	642.88	San Juan	SCH
T35.0S R25.0E Section 2.0SL	638.4	San Juan	SCH
T35.0S R25.0E Section 16.0SL	640	San Juan	SCH
T35.0S R26.0E Section 16.0SL	640	San Juan	SCH
T35.0S R26.0E Section 32.0SL	640	San Juan	SCH

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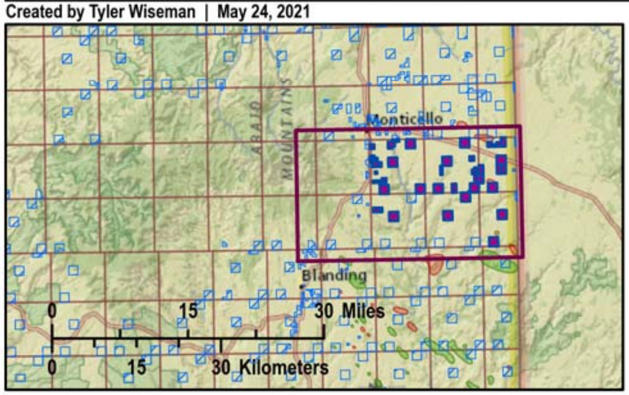


RCS Resources, LLC

Montezuma Creek OBA Exhibit A Map: San Juan County, Utah

Bureau of Land Management
National Forest
Other Federal
Private
State Trust Lands (SITLA)
Other State
All SITLA Minerals
Partial SITLA Minerals

Exhibit A Lands [14,672 Total Acres]
Gunnison Sage Grouse [Occupied]
Gunnison Sage Grouse [Potential]
Oil Field
Gas Field
Inert Gas Field

Location Abandoned
Plugged Abandoned
Producing Gas Well
Returned APD
Shut-in Gas Well

10g

Book Cliffs OBA (Helium)

BOARD MEMORANDUM

DATE: June 7, 2021

TO: Board of Trustees, Utah School & Institutional Trust Lands Administration (SITLA)

FROM: Wesley Adams, Assistant Director – Oil & Gas

RE: Book Cliffs OBA; Grand and Emery Counties, UT.

LANDS PROPOSED:

Grand and Emery Counties, UT

24,322.64 Acres (shown on attached Exhibit Map)

FUND: School 91%
Utah State University 6.6%
NS 1.79%
IB .32%

APPLICANT:
Five-Nines Resources, LLC
Attn: John Kinnebrew
401 Edwards Street, Suite 2100
Shreveport, LA 71101

REQUIREMENT
As provided for under Utah Code Annotated 53C-2-401(1)(d)(ii), which permits the SITLA Board of Trustees to approve "Other Business Arrangements" (OBA), Five-Nines Resources, LLC (FNR) submitted a proposal to SITLA for leases covering helium, oil, gas and associated hydrocarbons on May 26, 2021.

This proposed OBA was reviewed by the SITLA Board Mineral Committee on June 3, 2021. The committee requested improvements and has provided a recommendation for approval before the full Board of Trustees on June 17, 2021.

PROPOSAL

FNR is proposing a helium-based exploration concept that will establish lease blocks of three to four scattered sections for an initial paid-up lease term of 3-years at $3/ acre bonus and carry the option of an additional 2-years with a paid-up $6/ acre bonus, if two exploratory wells are dilled within the initial 3-year terms. The two test wells will be drilled within the Harley Dome and Woodside Prospects to a depth sufficient to test the Entrada formation. If the test wells are not drilled, FNR will forfeit all leases not held to production at the end of the 3rd year. Royalty of 12.5% with not post-production costs allowed, subject to proportionate reduction if pooled with other mineral owners. If the two well drilling obligation is met, FNR will earn the option to acquire additional acreage (17, 359.63 acres) under the same terms as the initial 24,322.64 leased acres. FNR requests confidentiality on all proprietary information shared with SITLA regarding this OBA.

RECOMMENDATION

The SITLA Oil & Gas team reviewed FNR's proposal and recommends that the SITLA Board of Trustees grant approval to issue an OBA as outlined below in key points:

1. Issue new leases to FNR covering 24,322.64 acres, not to exceed 2,560 acres per lease, effective July 1, 2021 with 3-year initial primary terms. Royalty of 12.5% with no post-production costs. Leases will have an option to extend primary terms for 2-years, if two test wells are drilled during the initial 3-years terms. Leases will be covered by a Pugh Clause, releasing any lands not reasonably held by production at the end of the tenth year from the initial anniversary of July 1, 2021, or 2-years after the contraction of a unit or exploratory agreement with SITLA, whichever is later.

2. Bonus payments as follows:
    - $3/ acre paid up for initial 3 years
    - $6/ acre paid up for optional 2 years

3. FNR must complete drilling of two test wells to the Entrada formation within the original 3-year primary terms or all leases not held to production will expire and the end of year 3, as will the 2-year option to extend primary terms.

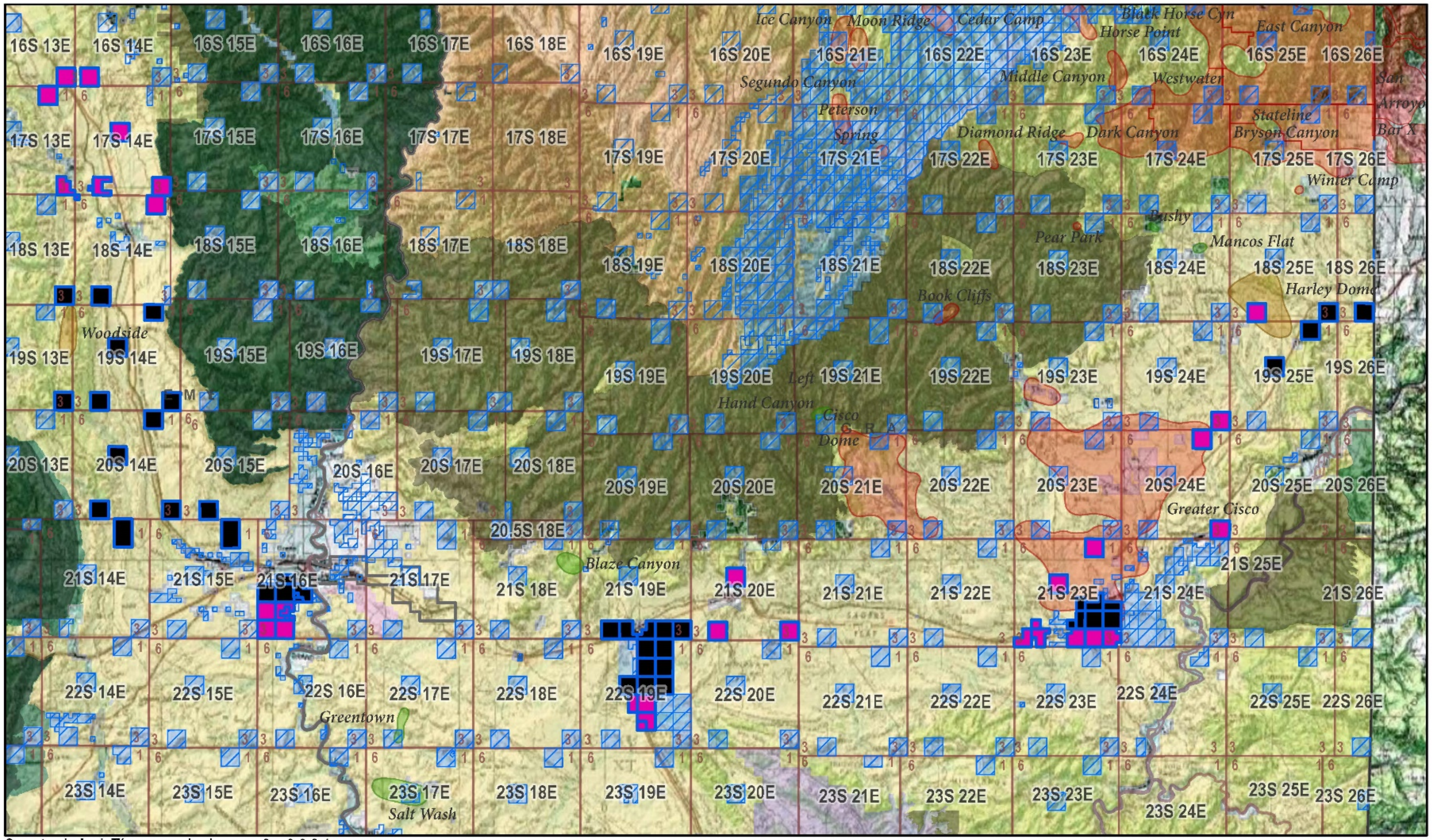
4. Additional Lease Options: (17,359.63 acres outlined on Exhibit Map) will be offered under a right of first refusal. Failure to drill the above two test wells will result in the termination of this option. ROFR can be exercised by FNR if no other expression of interest is received and after two wells are drilled or three years from September 1, 2021, whichever occurs first.

5. SITLA Exploratory Agreement: If the two test wells are drilled and the 2-year option to extend the initial leases is exercised, FNR will have the right to negotiate an exploratory agreement with SITLA in good faith, including additional drilling commitments and a reasonable timeline to explore non-producing leases, including any ROFR leases that may be acquired.

6. SITLA has the right to review scientific data collected under leases earned in this OBA upon request, including information that may be held confidential for proprietary reasons or interpretive risk.

Respectfully submitted,

Wes Adams
Assistant Director – Oil & Gas



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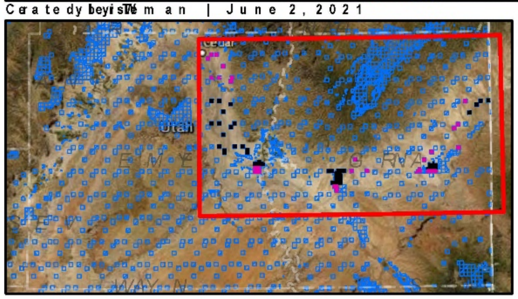

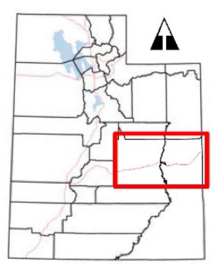

Five-Nines Resources,

Book Cliffs CEX Hibit Map: Emery & Gran

- Bureau of Land Management
- National Parks & Historic Sites
- National Wilderness Area
- Military Reservations
- Private
- State Trust Lands (SITLA)
- State Sovereign Land
- State Parks and Recreation
- State Wildlife Reserve
- Other State
- Tribal Lands
- BLM Wilderness Study Area
- PLSS Township-Range
- All SITLA Minerals
- Partial SITLA Minerals
- **FNR Exhibit "A" Acreage [24,322.64 Acres]**
- **FNR Exhibit "C" Option Acreage [17, 359.63 Acres]**
- Oil Field
- Gas Field
- Inert Gas Field

0 10 20 Miles

0 10 20 Kilometers