1. Alternatives

1.1 Mancos Shale Planning Area

The Southern Ute Indian Reservation is located in southwestern Colorado, in the southern portion of La Plata and Archuleta counties, with a small tract in eastern Montezuma County (Map 1). The Reservation encompasses approximately 681,000 acres, or 1,070 square miles, and includes a patchwork of Tribal and non-Tribal (private) lands and minerals. The Mancos Shale Planning Area (the "Planning Area") encompasses approximately 107,253 acres within the Reservation in La Plata County.

The Planning Area is primarily located on the Mesa Mountains, generally south and west of Ignacio, Colorado, and extends south to the New Mexico-Colorado state line (Map 1). The legal description of the Planning Area is listed in Table 1-1.

Table 1-1. Planning Area Legal Description

Township/Range	Section
Township 33 North, Range 10 West	1, 12, 13, 14, 23, 24, 25, 26, 35, 36
Township 32 North, Range 10 West	1, 2, 11, 12, 13, 14, 15, 22, 23, 24
Township 33 North, Range 9 West	All
Township 32 North, Range 9 West	All
Township 33 North, Range 8 West	4, 5, 6, 7, 8, 9, 13, 14, 15, 17-36
Township 32 North, Range 8 West[1]	All
Township 33 North, Range 7 West	18-36
Township 32 North, Range 7 West[1]	All

[1] This Township and Range has 24 Sections.

Note: Legal description based on the New Mexico Principal Meridian.

Surface and subsurface ownership within the Planning Area varies. Indian interests include surface and mineral resources that are Tribal Trust, allotted, or purchased. These terms are defined as:

- Tribal Trust Land: Land held in trust for the Tribe by the federal government.
- Allotted Trust Land: Land held under restricted patents or in trust by the federal government for the benefit of individual Native Americans
- Tribal Purchase: Private land the Tribe has purchased
- Tribal Minerals: Mineral estate held in trust for the Tribe
- Allotted minerals: Mineral estate owned by allotees

Maps 2 and 3 display the surface and mineral ownership in the Planning Area, respectively. The surface and mineral ownership, which comprises the Tribal interest, is listed in Table 1-2.

Table 1-2. Tribal Interest in the Planning Area

Surface and Mineral Ownership in the Planning Area	Acres[1]
Private	46,047
Tribal Trust	58,819
Tribal Purchase	2,387
Total Surface Ownership	**107,253**
Allotted Oil and Gas	1,841.
Private Oil and Gas	41,880
Tribal Trust Oil and Gas	63,528
Total Mineral Ownership	**107,249**

[1] Acres calculated from the 2026 Tribal Department of Energy surface and subsurface geographic information system layers.

Note: Acres may not sum exactly due to rounding in geographic information systems for multiple parcels.

1.2 Development Aspects Common to Both Alternatives

Individual operators may approach the exploration and development of the Mancos Shale differently, depending on the location of leased minerals, surface constraints, and site-specific characteristics. Mancos Shale development is expected to evolve as technological advances in drilling and completion methods and as more reservoir data are compiled.

Drilling, completions, construction, production, and reclamation are assumed to be conducted in the same manner under both the Proposed Action Alternative and No Action Alternative. The following sections describe these development phases, and the assumptions regarding how exploration and development will take place that are common to both alternatives.

1.2.1 Horizontal Well Drilling Technology and Spacing

Horizontal drilling is a technique used to drill from the surface to a target reservoir, then curve the wellbore to run parallel (lateral) to the reservoir's more extensive horizontal dimensions, maximizing exposure of the reservoir to the wellbore and increasing production.

The depth of the target Mancos Shale on the Reservation is approximately 7,000 feet below ground surface. Two horizons in the Mancos Shale gas play were identified for potential development: the Lower Bench and Upper Bench. Designated spacing units can vary in size for different reasons including limiting surface impacts. The anticipated spacing for development is eight wellbores (wells) producing within designated spacing units consisting of 2 to 4 governmental land sections, depending on the length

of the well laterals. Four well laterals could be drilled in the Mancos Shale Upper Bench and four in the Mancos Shale Lower Bench, with approximately 1,200 feet of horizontal spacing between laterals in the same bench. Figure 1-1 illustrates the spacing of 2-mile-long laterals in the Mancos Shale Upper and Lower benches.

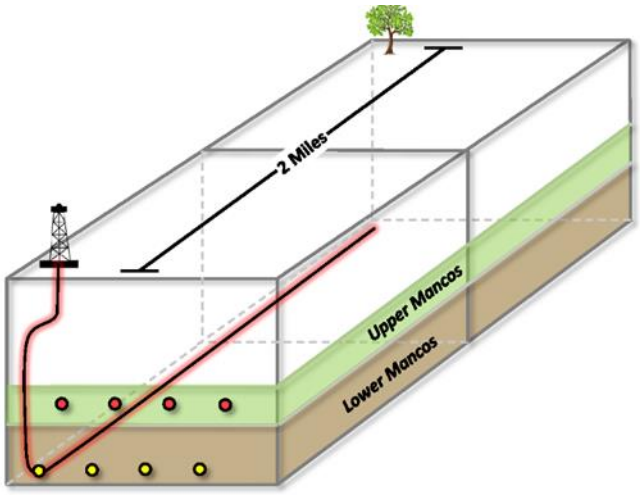


Figure 1-1. Diagram of Horizontal 2-Mile Lateral in Lower Mancos Shale Bench

The conceptual design is based on eight horizontal wells per 2, 3, or 4 section designated spacing unit (Figure 1-1). Initial estimates anticipate laterals to be primarily 2 miles in length. However, technological advancements are enabling the successful drilling of longer laterals (i.e., greater than 2 miles). A greater number of longer laterals would reduce the number of well pads and wells required to access the same mineral resources. Wells would be drilled in an east-west alignment due to regional stress considerations within the Mancos Shale.

The Colorado Energy and Carbon Management Commission (ECMC), in conjunction with the Bureau of Land Management (BLM), has designated several spacing units for the Mancos Shale within the Planning Area for appraisal well drilling.

1.2.2 Construction

Descriptions of well pad, pipeline, and access road construction techniques typically used for hydrocarbon development within the Planning Area are detailed in Appendix TBD. While the techniques and procedures described could be applicable to all well pad, pipeline, and access road construction, some operators may use techniques and procedures that vary slightly. The Tribe, the Bureau of Indian Affairs (BIA), and/or the BLM would determine the suitability of an operator's design, construction techniques, and procedures during the site-specific permitting process, as applicable.

Well pad size would vary depending on the number of wells drilled and whether water for drilling and completions would be stored on the pad or at an off-site location. For details on water storage and the

differences in amounts between the alternatives, see Sections 1.3.3 and 1.4.3. If a large enough site cannot be identified for a well pad, more than one well pad may be needed to access the mineral estate in a particular area. Currently, pad size is expected to range from 8 to 18 acres during drilling and completions.

1.2.3 Well Drilling

Drilling operations for wells producing from Tribal or Allotted Minerals will be conducted in compliance with applicable federal and Tribal rules, regulations, and guidance documents. Drilling is a 24-hour, 7-day-a-week operation until the bottomhole location is reached. Drilling times would vary depending on the horizontal wellbore length and are expected to decrease over time as efficiencies are realized. Drilling could occur year-round, but between December and March it may be temporarily shut down due to inclement weather. Table 1-2 lists the estimated average drilling and completion times per lateral length. Well completion is discussed further in Section 1.2.4.

Table 1-2. Estimated Average Drilling and Completion Times per Lateral Length

Phase	2-Mile Lateral (days)	3-Mile Lateral (days)	4-Mile Lateral (days)
Drilling	30	34	40
Completion	7	10	15

Note: Completion estimate time assumes zipper fracturing operations.

Equipment located on the well pad during drilling would include the drill rig and associated equipment (e.g., blowout preventer, gas buster, generators, closed-loop tanks, etc.), pipe storage, and office and housing trailers for personnel.

A drilling plan would be submitted with each Application for Permit to Drill (APD) and would specify the drilling, casing, and cementing program. Each applicant would design casing specifications on a site-specific basis. Surface casing would extend to a depth below alluvial freshwater aquifers. The casing and cement would stabilize the wellbore and protect any overlying freshwater aquifers by isolating hydrocarbon zones from them. Proposed casing and cementing programs involving development of Tribal and Allotted minerals would be reviewed by BLM geologists and petroleum engineers, as well as the Tribe's Department of Energy (DOE), to ensure that the wellbore construction design is adequate to protect the surface and subsurface environment.

Drilling fluids are used to aid in drilling, and fluid mixtures are continually being redesigned and developed. Drilling fluid, or "mud", cools and lubricates the bit, while lifting the well cuttings generated by the bit to the surface for examination and disposal. The mud in the wellbore prevents the walls from sloughing into the hole, maintains stable underground pressures, and seals the wellbore walls by forming a thin mud cake. Drilling mud is typically mixed on location and stored in steel bins. Mud properties are carefully monitored, and mud specialists take daily physical and chemical measurements of the mud. Both water and oil-based drilling fluids could be used.

Water-based drilling fluid would likely consist of freshwater, bentonite, barite, clay stabilizers, friction reducers, and fluid-loss control materials. During horizontal drilling operations, a brine mixture containing fluid-loss control material and calcium chloride is used as a weighting agent. Currently, in typical drilling activities within the Reservation, water-based drilling fluid density is normally between 9.8 and 10.6 pounds per gallon (ppg) with low to no salinity.

Oil-based fluids in use today are formulated with diesel, mineral oil, or low-toxicity linear olefins and paraffins. Olefins and paraffins are often referred to as synthetic materials. Oil-based muds minimize clay reactions, swelling, or sloughing; downhole temperatures; and stuck pipe, torque, and drag. Oil-based systems usually contain lime to maintain an elevated pH, resist the adverse effects of hydrogen sulfide (H_2S) and carbon dioxide (CO_2) gases, and enhance emulsion stability. Oil-based mud density ranges between 10.8 and 11.8 ppg with salinity between 100,000 and 200,000 parts per million (ppm).

A water-based drilling mud would be used to set the surface casing to the required depth, after cementing the intermediate string. A synthetic oil-based drilling mud may be used to drill the horizontal portion of the wellbore. Oil-based muds are used only within the shale reservoir rock and are not used adjacent to freshwater aquifers.

During drilling, the returns (cuttings and fluids) rise up the annulus (the area between the drill pipe, bit, and formation) and enter a separation vessel. The separation vessel uses a misting device to separate particles from the air and then vents the air to a flare line. The flare line carries gas to a flare stack, where any combustible gases (primarily methane) are burned, and any non-combustible gases (primarily nitrogen) go back into the atmosphere. All flowback practices would be compliant with 40 Code of Federal Regulations (CFR) 60 Subpart OOOO. Venting and flaring would be consistent with 43 CFR 3179 regarding waste prevention and resource conservation, as implemented in 2024.

Wells would be drilled using closed-loop drilling systems. Closed-loop systems employ a suite of solids control equipment to minimize drilling fluid dilution. This type of system results in a location where a pit is not required, used fluids are recycled, and solid waste is dried and disposed of properly. The percentage of fluids that are typically recycled or reused is 50 to 80 percent. After most of the water is removed from the cuttings using a shaker and centrifuge, the cuttings are stored in a bermed and lined "drying bed" or a steel roll-off bin and allowed to dry further. Cuttings would be transported to an approved disposal facility.

1.2.4 Well Completion/Stimulation

Wells are often treated during completion to enhance resource recovery by increasing the rate and volume of hydrocarbons flowing from the natural gas and/or oil reservoir into the wellbore. These processes, known as well-stimulation treatments, include hydraulic fracturing, acidizing, and other mechanical and chemical treatments, often used in combination.

Hydraulic fracturing would be used to complete the wells considered in this development. Hydraulic fracturing is a process used to maximize the extraction of underground resources by allowing oil or natural gas to flow more freely from rock pores to production wellbores, which bring the oil or gas to the surface.

During hydraulic fracturing, a series of charges is set through the target producing interval in the horizontal portion of the wellbore to perforate the production liner and casing and create small fractures in the target formation. Fracturing fluids are then pumped into the wellbore at high pressure. When the fluid pressure exceeds the rock's strength, the fluid opens or enlarges fractures. After the fractures are created, a propping agent, typically sand, is pumped into the fractures to keep them from closing when the pumping pressure is released (USEPA 2016). Approximately 23 million pounds of sand would be needed to complete a 10,000-foot-long (2-mile) lateral.

Fracturing fluids are primarily water with additives that prevent corrosion, kill bacteria, reduce friction, and stabilize clays in the formation. Hydraulic fracturing fluids are well-specific; the exact formulation is not determined until stimulation occurs. Since 2011, operators have been disclosing the well-specific hydraulic fracturing fluids used in stimulations on the FracFocus website (http://fracfocus.org/). In 2016, the Tribe adopted Hydraulic Fracturing and Chemical Disclosure Regulations that require all operators on Tribal lands to report on the FracFocus website. Hydraulic fracturing activities would be governed by the applicable rules and regulations at the time of permitting (Southern Ute Indian Tribe 2016).

The hydraulic fracturing operation is conducted in multiple stages along the wellbore's horizontal section. Each stage is completed sequentially to create fractures in the target formation. After all stages have been pumped, the well is cleaned out, allowing oil or gas to flow. Existing completion methods may be improved, or new technologies advanced, over the lifetime of the Mancos Shale development. All well completion operations involving hydraulic fracturing would comply with the requirements under 40 CFR 60 Subpart OOOO §60.5375, as well as the Tribe's Hydraulic Fracturing and Chemical Disclosure Regulations applicable to Tribal and Allotted minerals.

Completions would likely use a "zipper frac" technique. A zipper frac improves efficiency by performing hydraulic fracturing in alternating stages on two parallel, closely-spaced horizontal wells from a single pad. While one well's stages are being pumped, a wireline crew prepares the other well for its next stage. This "zipper-like" alternating process allows both crews to work continuously, eliminating idle time. Additionally, the fractures propagate towards one another, forming a complex, interconnected system. This method has been found to increase production rates and maximize the stimulated reservoir volume compared to traditional single-well completion methods.

Flowback involves removing the liquids used to complete the well. For the duration of flowback, all recovered liquids and gases would be captured, processed, and disposed of in accordance with 40 CFR 60 Subpart OOOO §60.5375. The flowback fluid would be filtered to remove solids and then transported by truck or pipeline to an injection well or an approved disposal site. Flowback fluid may also be recycled and used for additional completions. Based on initial appraisals, well drilling and production data suggest that approximately 5 to 10 percent of the water used for completions would be returned to the surface as flowback over the well's life.

Green completion technology can be utilized in areas where sufficient infrastructure is already in place. Green completions occur during the flowback stage of the completion process. During flowback, natural gas may be produced with the water. What makes the well completion "green," or environmentally friendly, is that the gas is separated from the water and piped for sale instead of being flared.

1.2.5 Roads

The existing road network would be used as much as practicable; however, short resource roads would likely be needed to access new well pad locations. Therefore, new road building would likely be limited to connecting well pads to existing roads. New well pad roads added to the existing network are assumed to be an average of 0.25 mile in length. New roads would be co-located with well-connect pipelines, unless it is determined during the site-specific on-site that topography or other issues warrant separate routes.

Descriptions of access road construction techniques typically used for natural gas extraction within the Planning Area are detailed in Appendix TBD. Existing and new roads would be maintained in the same or better condition than existed prior to the commencement of drilling and operations, and maintenance would continue until final abandonment and reclamation of the well pad. New access roads would be designed and constructed in accordance with the BLM Gold Book Standards (USDI/USDA 2007). Construction would include ditching, draining, installing culverts, crowning and capping or sloping and dipping the roadbed, and installing pullouts, as necessary, to provide a well-constructed, safe road.

Based on factors such as topography, soils, hydrology, safety, and the levels and types of use by the operator and public, some roads may require professional engineering design and construction oversight. The need for a professionally engineered design would be determined on a case-by-case basis.

1.2.6 Production

Production facilities on the well pads may include wellheads, metering units, separators, dehydrators, aerial coolers, compressors, and aboveground tanks. On-site production equipment would be powered by micro-turbines, solar skids with battery backup, or other solutions if electrical distribution infrastructure is unavailable.

The size and number of tanks on-site would be dependent on production volumes. However, it is estimated that for the short term during flowback, there would be six 500-barrel (bbl) frac tanks for flowback fluids and two 500 bbl produced water storage tanks. In the long term, two 500 bbl produced water storage tanks would be installed on each pad and support up to eight wells.

Tank batteries would be placed within secondary containment and sized to contain at least 110 percent of the storage capacity of the largest single tank within the containment structure or berm, to account for potential spill volume and additional precipitation. Containment berms would include an impermeable liner attached to the tank stabilizing rings and laid under the tanks. All loading lines would be placed within the containment structure or would be equipped with secondary containment vessels.

Produced water from the Mancos Shale is expected to be minimal because water imbibes into the formation and becomes bound by capillary forces. Based on appraisal well drilling, the amount of produced water, which includes flowback from completions, is 5 to 8 percent of the completion's water volume. For a 2-mile lateral with a typical completion fluid volume of 650,000 bbl, a 10 percent recovery would equate to 65,000 bbls over the life of the well. Produced water would be stored on-site in aboveground tanks and then either used for completions of other wells or disposed of in accordance with

regulations. For produced water disposal, it would be transported via subsurface pipelines or by truck to a central delivery point or an existing saltwater disposal well (SWD) facility. Produced water pipelines may be constructed concurrently with gas pipelines and laid within the same right-of-way (ROW).

Some wells occasionally require recompletion to maintain production. The frequency and need for future recompletions of the Mancos Shale are unknown. If downhole activity is proposed, the design would be evaluated by the BLM and the Tribe's DOE to ensure all aquifers and other nearby wells are protected.

1.2.7 Interim Reclamation

Following completion activities of all wells drilled from the pad, a portion of the pad not required for production equipment and vehicular access would be re-contoured and reclaimed. Depending on the number of wells per pad, approximately 6.5 to 10 acres per pad would remain in use for production and vehicle access. Other facilities, such as multi-well fluid management facilities, would also be reclaimed once they are no longer needed for future development. After pipelines are installed, the associated construction corridor would be reclaimed. Standard reclamation practices include soil contouring to blend smoothly with the surrounding landscape, uniform spreading of stockpiled topsoil, seedbed preparation, seeding, and mulching and crimping. Reclamation practices would adhere to any grant of easement or lease stipulations and/or the Tribe's Range and DOE stipulations. Appropriate erosion and sediment control best management practices (BMPs) as outlined in the Tribe's Stormwater Recommendations Policy would also be implemented.

1.2.8 Final Abandonment and Reclamation

Each well would have a lifespan of 20 to 40 years. Upon final abandonment, the well locations, production facilities, pipelines, and access roads would undergo final reclamation to restore the land's character and productivity. During final reclamation, surface equipment would be removed. Soil would be sampled for any contaminants of concern in accordance with the Tribe's DOE policies, and disturbed areas would be re-contoured as closely as possible to the original landform. Salvaged topsoil would be respread and the area prepared for seeding (i.e., tilled, disked, harrowed), seeded, mulched, and crimped. A reclamation plan would be included in the Surface Use Plan of Operations developed for each APD, as applicable. Roads and pipelines would be reclaimed as outlined in the project-specific stipulations. Additional reclamation measures may be required based on the conditions existing at the time of abandonment.

1.3 Proposed Action Alternative

The Proposed Action would develop Mancos Shale gas resources within the Planning Area from existing valid mineral leases utilizing horizontal drilling technology over the next 20 to 30 years.

Due to the programmatic nature of this document, the exact locations and timing of activities, including drilling of wells and installation of equipment and facilities, are unknown. However, the Tribe's DOE, in coordination with operators, developed a hypothetical, or conceptual, plan to maximize use of existing infrastructure and minimize new disturbances. Conceptual well pad locations and other infrastructure were preliminarily identified to help guide development and allow for comparison between action

alternatives (Map 4). All activities and construction related to a particular project, including location siting and reclamation specifics, would be evaluated in detail on a site-specific basis through the APD, ROW grant, or surface lease process at the time each project is proposed.

The assumptions for the Proposed Action are:

1. Development would average 40 miles of horizontal laterals (e.g., 20 wells with 2-mile laterals, 10 wells with 4-mile laterals, or some combination thereof) per year over 20 to 30 years.
2. There may be years when this average is exceeded due to economics or other constraints, and years when fewer than 40 miles of horizontal lateral are completed. The maximum annual completions anticipated are 60 miles of horizontal laterals due to constraints on the availability of Tribal water for drilling and completions.
3. Operators would be encouraged to share well pad locations and use existing pipeline infrastructure to transport gas and water.

Miles of lateral drilled per year, rather than the number of well pads or wells developed per year, are used to describe the action alternatives because the number of wells and the length of the wellbore laterals can vary across pads. Additionally, water and traffic volumes are quantified per mile of lateral for comparative analysis.

1.3.1 Estimated Development

Future development would use existing well pads and ROWs throughout the Planning Area to the extent possible. Multiple horizontal wells would be drilled into adjoining sections from co-located pads. Co-located pads are defined as those that may be adjacent to, overlap, or expand an existing pad. In general, the Proposed Action would include the estimated development of:

- Up to 68 well pads with an estimated 80 percent co-located with existing pads
- Up to 466 horizontal wells over 30 years with approximately:
  - 40 percent 2-mile laterals
  - 40 percent 3-mile laterals
  - 20 percent 4-mile laterals
- Four to 16 wells per pad, but typically 8
- Associated road, water, gas, electric, communication, and compression infrastructure
- These components are addressed in more detail in the following sections.

1.3.2 Communitization and Unitization

Both communitization and unitization are encouraged by the Tribe and expected to be used during the implementation of the Proposed Action. Communitization enables the combined development of separate leases or portions thereof that cannot be independently developed and operated in accordance with an

established well spacing unit. Communitization combines mineral interests within a spacing unit and allocates production and royalties based on the proportionate mineral acreage within the area of the communization agreement. Unitization allows multiple leases to be operated as a single lease, enabling a single operator under an operating agreement. Spacing units are vacated, and lease lines are disregarded, allowing for flexibility in development. Unitization and communitization are cooperative agreements. These agreements pool the interests in the area covered and allow for greater recovery of the resource, minimize surface impacts, and prevent waste. The specific leases that would be subject to communitization or unitization agreements are currently unknown and would be identified as development proceeds.

1.3.3 Water Use and Management

Water would be used during drilling and completions. The amount of water would vary depending on the type of drilling or completion fluids used, the lateral length, and the number of hydraulic fracturing stages. Water would also be used for other activities, such as rig washing, coolant for internal combustion engines, dust suppression on roads or well/facility pads, equipment testing, and reclamation.

The primary water source would be freshwater allocated by the Tribe from its water rights in the Animas-La Plata Project (ALP) and Pine River Project.

Due to the minimal amount of water found in the Mancos Shale in the Planning Area, produced water is not available in sufficient quantities to use in drilling and completions. However, freshwater, produced water, or a combination of freshwater and produced water could be used if available, and depending on the necessary mud or fluid properties.

The following assumptions were used to determine the amount of freshwater that may be required for the Proposed Action.

- 7,500 bbls (about 0.95 acre-feet) of water for non-completion related activities per 1-mile lateral and 15,000 bbls (about 1.9 acre-feet) per 2-mile lateral, which may be a combination of freshwater, produced water, and/or recycled water
- 325,000 bbls (about 41.9 acre-feet) of water to complete a 1-mile lateral and 650,000 bbls (about 83.8 acre-feet) of water to complete a 2-mile lateral
- An average of 40 miles of laterals drilled and completed annually
- A maximum of 60 miles of laterals drilled and completed annually

The timing of freshwater depletion is unknown. If water is removed during spring runoff, it is much less perceptible than during low-flow conditions. Water may be removed during peak flows and stored for future use, in accordance with approved water rights. Table 1-3 lists the total annual estimated water use for the Proposed Action. The preferred pace of development desired by the Tribe would be 40 miles of horizontal lateral per year, but could range up to the anticipated maximum of 60 miles of horizontal lateral.

Table 1-3. Estimated Water Use for the Proposed Action

Amount of Development	Non-Completion Activities (acre-feet)[1]	Completion (acre-feet)	Total (acre-feet)
40 miles lateral/year	38	1,676	1,714
60 miles lateral/year	57	2,514	2,571

[1] Based on 20 wells per year. Depending on lateral length, fewer or more wells may be drilled each year.

Freshwater made available by the Tribe would be sourced from take-out points on the Animas River and the Pine River, with conceptual locations shown on Map 4. Site-specific locations for these take-out points have not yet been identified. Water would be transported from the rivers by lay-flat line using associated pump stations laid within approved ROWs. Additional lay-flat lines and pumps would be used to transport water from the Pine River. A lay-flat line is a tough, synthetic rubber pipeline that forms a single, homogeneous hose structure, temporarily installed above ground to transport water. Using lay-flat lines minimizes disturbance and decreases vehicle traffic from water transport.

Under the Proposed Action, water would be sourced from the rivers and lay-flat lines would be installed to transport it from the rivers to centralized water storage facilities and then to the well that is being drilled and completed. The Tribe's DOE estimates that six potential off-site storage facilities would be needed, with conceptual locations shown on Map 4. However, during actual development it is possible that more locations may be required. Each storage facility would support a battery of aboveground storage tanks (ASTs). One 10-acre centralized storage facility would provide drilling and completions water to multiple wells within a radius of approximately 2 to 6 miles. All flowback and produced water would be trucked or hard piped from the well pad for disposal. During the flowback period, all recovered liquids and gases would be captured and processed as required under 40 CFR 60 Subpart OOOO, §60.5375(a). Given the amount of water needed for completions, additional ASTs would be located on or adjacent to individual well pads to store water temporarily.

Permanent Buried Water Line

Depending on commodity prices, economic conditions, and the level of Mancos Shale development, a permanent, buried freshwater pipeline could be constructed in the future, connecting the Animas and Pine rivers to the centralized tank batteries. The conceptual alignment is shown on Map 4. If constructed, the water pipeline would be approximately 20 miles long and co-located with existing and new pipeline infrastructure. The pipeline would be constructed within a 60-foot-wide ROW. At least two pump stations would be needed to facilitate transporting water upgradient. Upon completion of the Proposed Action, the water pipeline would remain in place and could be used for municipal or industrial purposes.

1.3.4 Electrification

Under the Proposed Action, approximately 13.2 miles of new 115-kilovolt (kV) electric power line and three substations would be constructed. Although the specific location of these lines has not been determined, a conceptual rendering is provided in Map 4. The construction corridor for the power line

would be up to 50 feet wide. Each substation would occupy approximately 5 acres. This infrastructure would serve to electrify well locations and five existing compression facilities. This would reduce emissions from facilities powered by natural gas or diesel engines.

1.3.5 Compression and Dehydration

Based on appraisal well data, the Mancos Shale is normally to slightly over normal pressure. These wells would initially be able to deliver into high- and medium-pressure pipelines. Compression to reduce wellhead pressure and, in turn, reservoir abandonment pressure would ultimately be necessary to achieve economic recovery of the resource. A range of factors could affect each operator's decision on timing, but some may install compression as early as 18 months, while others may wait 3 to 5 years after first delivery.

Currently, there are 26 tribally-operated compression facilities with varying amounts of horsepower at each site within or adjacent to the Planning Area, with underutilized compression to support the compression requirements. Under the Proposed Action, wells in low-pressure service are estimated to need 28 additional compressor units at existing and new facilities (1,200 horsepower [hp]/unit). The additional units are anticipated to be located in:

- Corridor 1; 4 units (existing facility)
- Corridor 2; 8 units (new facility)
- Corridor 3; 8 units (new facility)
- Corridor 5; 8 units (new facility)

Each new facility would be approximately 3.5 acres in size.

Dehydration in natural gas production removes water vapor to prevent corrosion in pipelines and equipment, prevent the formation of solid methane hydrates, and meet transport water content standards. Initially, each well (or pad) would need a dehydration unit on-site to remove water from produced gas; however, as reservoir pressure decreases, the produced gas would be transported via medium- to low-pressure pipelines, and dehydration would take place at centralized facilities (adjacent to compression facilities) rather than on-site. The installation and operation of gas dehydration facilities would be required for both medium-pressure and low-pressure service throughout the well's producing life. Dehydration units would be moved from one pad to another as pressures decline and as the development progresses.

1.3.6 Pipelines

Well-Connect Pipelines

Well-connect pipelines would be used to transport Mancos Shale gas from a well into either an existing or a new gathering system (trunk pipelines), depending on the quality and quantity of the gas, existing infrastructure, pipeline capacity, and contractual obligations. Operators would be encouraged to use existing infrastructure whenever possible.

Well-connect pipelines would range from 6 inches to 20 inches in diameter. The well-connect pipelines would typically be located within a 40-foot-wide ROW and may also include the installation of a 4- to 6-inch-diameter produced water pipeline, buried electric line, and/or fiber optic communication line. New well-connect pipelines and other utilities would be co-located with existing or proposed access roads or existing ROW corridors as much as possible. Well-connect pipelines are not shown on Map 4, because the well pad locations are conceptual. It is assumed that new well pads would need an approximately 0.25-mile-long access road and a co-located well-connect pipeline.

Trunk (Gathering) Pipelines

As part of the Proposed Action, the Tribe's DOE identified five main pipeline corridors in the Planning Area based on the level of existing infrastructure, such as roads and existing pipelines, and their proximity to suitable well pad locations. The Proposed Action estimates that approximately 58.9 miles of trunk pipelines would be needed to support the development, including both medium and low-pressure trunk lines. Medium-pressure pipelines would operate between 350 and 500 pounds/square inch (psig), and low-pressure pipelines would be anything below 350 psig. These conceptual trunk pipeline corridors are shown on Map 4. The gathering system would consist of buried pipelines up to 24 inches in diameter. For this analysis, regardless of pipe size, the gathering system would be constructed within a corridor up to 60 feet wide.

Related aboveground appurtenances (e.g., pig launchers, receivers, valve assemblies, or other objects attached to a horizontal component or riser) that could be installed within the pipeline workspace would include cathodic protection equipment and security fencing, where necessary.

Pipelines would be constructed in accordance with Federal regulations and standards, and environmental protection measures would be implemented. Following construction, pipeline disturbance would be fully reclaimed. Descriptions of pipeline construction techniques typically used for natural gas extraction within the Planning Area are detailed in Appendix TBD.

1.3.7 Estimated Disturbance

The estimated disturbance associated with implementing the conceptual Proposed Action is presented to allow for comparative analysis and is based on the best available information. The actual amount of surface disturbance may vary from the estimated amount and would depend on site-specific proposals. Site-specific environmental and cultural analyses, as well as additional NEPA compliance, would be required for all future site-specific proposals. The estimated amount of short-term and long-term disturbance per project component is listed in Table 1-4. Disturbance was estimated based on the following assumptions:

- 68 well pads at 18 acres per pad for construction and drilling; 10 acres per pad for operation
- 20 percent new well pads needing approximately 0.25-mile-long access road and well-connect pipeline constructed within a 40-foot-wide construction corridor reclaimed to a 30-foot-wide long-term corridor
- 58.9 miles of trunk pipeline in a 60-foot-wide construction corridor

- six off-site water storage facilities at 10 acres each
- 20 miles of permanent buried freshwater water line within a 60-foot-wide construction corridor
- 13.2 miles of powerline in a 150-foot-wide construction corridor
- three substations at 5 acres each
- three compressor stations at 3.5 acres each

Temporary surface lay-flat lines would be placed within proposed and existing corridors and are not expected to result in additional disturbance.

Table 1-4. Proposed Action Estimated Short- and Long-term Disturbance

Component	Short-Term Disturbance (acres)	Long-Term Disturbance (acres)
Well pads	1,224	680
Access roads/well connect pipeline	17	13
Off-site water storage	60	60
Permanent buried freshwater water line	145.5	0
Trunk pipelines	428.4	0
115-kilovolt power line	240	240
Substations	15	15
Compressor sites	10.5	10.5
Total	**2,140**	**1018.5**

1.4 Environmental Protection Measures

Please see the separate document for draft measures.

1.5 No Action Alternative

The BLM would continue existing APD management and approval on a piecemeal, case-by-case basis without new programmatic framework. Site-specific NEPA analysis would be conducted and tiered to existing NEPA approvals. Conditions of Approval would be developed for each APD consistent with existing BLM management practices.

All activities and construction related to a particular project would be evaluated in detail on a site-specific basis through the APD, ROW grant, or surface lease process at the time each project is proposed.

The assumptions for the No Action Alternative are:

1. Each operator would develop its leases independently, in the absence of the programmatic framework set forth in the Proposed Action.

2. Operators would maximize their capital expenditure by developing their leases more rapidly. In the absence of programmatic planning and associated mitigation measures, the timeframe for developing the Mancos Shale resource in the Planning Area is anticipated to be 10 to 15 years.
3. Approximately 80 miles of horizontal lateral would be drilled per year, compared to 40 to 60 miles per year under the Proposed Action.
4. Operators would develop individual well pads on lease, instead of co-locating pads with other operators at off-lease locations.
5. Operators would develop their own trunk pipelines on lease to connect to existing gathering lines at the lease line.
6. Operators may also develop off-lease pipelines to connect to processing facilities outside the Planning Area. The potential locations for pipelines connecting to processing facilities are unknown.
7. Compression would occur at the wellhead instead of at central locations.

As with the Proposed Action, the exact locations and timing of activities, including drilling of wells and installation of equipment and facilities, are unknown. Conceptual well pad locations and other infrastructure were identified by the Tribe's DOE based on operator leases and the assumptions above (Map 5).

1.5.1 Estimated Development

The No Action Alternative would include the estimated development of:

- Up to 117 well pads with an estimated 55 percent co-located with existing pads
- Up to 576 horizontal wells over 15 years
- Up to 16 wells per pad, but typically 8
- Associated road, water, gas, and communication infrastructure

Initial estimates for the No Action Alternative anticipate the proportion of laterals based on length as:

- 7 percent 1-mile laterals
- 66 percent 2-mile laterals
- 21 percent 3-mile laterals
- 6 percent 4-mile laterals

1.5.2 Communitization and Unitization

Under the No Action Alternative, operators are not expected to collaborate or enter unitization agreements with other operators to minimize infrastructure or disturbance. Communitization agreements

would continue to be implemented as necessary to allow for the development of independent mineral interests within a shared spacing unit.

1.5.3 Water Use and Management

The Tribe has made 3,000 acre-feet of freshwater available per year for purchase by operators for drilling and completions. Funds received for use of this water are intended to be used to improve and maintain the Pine River Irrigation District infrastructure, among other purposes.

Similar to the Proposed Action, the following assumptions were used to determine the amount of freshwater that may be required for the No Action Alternative.

- 7,500 bbls (about 0.95 acre-feet) for a 1-mile lateral and 15,000 bbls (1.9 acre-feet) of water for non-completion related activities per well, which may be a combination of freshwater, produced water, and/or recycled water
- 325,000 bbls (about 41.9 acre-feet) of water to complete a 1-mile lateral and 650,000 bbls (83.8 acre-feet) of water to complete a 2-mile lateral

However, it is assumed that up to 80 miles of horizontal lateral could be drilled per year (e.g., 40 wells with 2-mile laterals, 20 wells with 4-mile laterals, or some combination thereof) under the No Action Alternative, requiring an estimated 3,438 acre-feet of water. Table 1-5 lists the total annual estimated water use for the No Action Alternative.

Table 1-5. Estimated Annual Water Use for the No Action Alternative

Timeframe	Non-Completion Activities (acre-feet)[1]	Completion (acre-feet)[2]	Total (acre-feet)
80 miles lateral per year	76	3,352	3,428

[1] Based on 40 wells per year. Depending on lateral length, fewer or more wells may be drilled each year.

As with the Proposed Action, freshwater made available by the Tribe would be sourced from two take-out points within the Reservation: one on the Animas River and one on the Pine River.

Lay-flat lines would be installed to transport water from the take-out points to centralized water storage facilities, then to the well being drilled and completed. Each operator would use off-site storage facilities. Each storage facility would support a battery of ASTs. One 10-acre centralized storage facility would provide drilling and completions water for multiple wells. It is anticipated that each operator would require at least one off-site water storage facility for a lease greater than one Section (640 acres) in size. Under the No Action Alternative, each operator is expected to build multiple water storage facilities within the Planning Area instead of sharing facilities with other operators. Approximately 15 off-site water storage facilities are estimated to be needed.

For drilling, freshwater, produced water, or a combination could be used. For completions, the preferred method would be to use freshwater. Operators would need to access sufficient water volumes to drill and complete wells and would have limited options for sourcing water. Some potential water sources are discussed below.

Other Water Sources

Operators could purchase municipal water from the City of Durango, the La Plata/Archuleta Water District, the La Plata West Water Authority, or the Southern Ute Utilities bulk water stations. This water would need to be transported to a well site by truck.

Operators could purchase water from a private water rights holder. In Colorado, water use is governed by the Prior Appropriation System. This system controls who uses how much water, the types of uses allowed, and when those uses can occur (37-92-103(5) Colorado Revised Statutes [CRS]). A water right is a property right; therefore, it can be bought and sold, and, subject to certain limitations, moved and changed to apply to different uses. Operators would need to verify that the purchased water has been decreed for industrial use. If a change in water use classification is needed, the holder must file with the Colorado Water Court and demonstrate that no injury to others will result before approval.

1.5.4 Electrification

The 115-kV electric power lines contemplated under the Proposed Action would not be constructed because the Tribe would not likely invest the capital required for this infrastructure due to long-term uncertainty. No other electrical lines would be constructed except those required by the ECMC on fee lands. These would be determined at the site-specific development level.

1.5.5 Compression and Dehydration

As with the Proposed Action, this alternative would require compression for medium- to low-pressure wells. Operators would need to use compression at well pads to transport gas into their individual well-connect pipelines and gathering lines. It is unlikely that operators would invest in developing central compression facilities. A range of factors could affect each operator's decision on timing, but some may install compression as early as 18 months, while others may wait 3 to 5 years after first delivery. At least two compressors per well pad would be needed; however, more may be needed depending on low-pressure gas pipeline demands and individual well performance. Based on current production data, for every two wells (2-mile laterals) on a location, one 1,200 hp compressor would be needed. Based on approximately 1,200 miles of well laterals, the No Action may require up to 720,000 hp of compression at full development.

Initially, each well (or pad) would need a dehydration unit on-site to remove water from produced gas; however, as well pressure decreases, the produced gas would be transported via low-pressure pipelines, and dehydration would take place at centralized facilities rather than on-site. The installation and operation of gas dehydration facilities would be required for both medium-pressure and low-pressure service for the duration of the well's producing life.

1.5.6 Pipelines

Well-Connect Pipelines

Well-connect pipelines constructed under the No Action Alternative are assumed to be similar to those under the Proposed Action. They would range in diameter from 6 to 20 inches. Well-connect pipelines would typically be located within a 40-foot-wide ROW and may also include the installation of a 4- to 6-inch-diameter produced water pipeline, a buried electric line, and/or a fiber-optic communication line. New well-connect pipelines and other utilities would be co-located with existing or proposed access roads or existing ROW corridors as much as possible. Well-connect pipelines are not shown on Map 4, because the well pad locations are conceptual. It is assumed that new well pads would need an approximately 0.25-mile-long access road and a co-located well-connect pipeline.

Trunk (Gathering) Pipelines

Under the No Action Alternative, operators are expected to develop their own trunk pipelines on lease to connect to existing gathering lines at the lease line. The No Action Alternative estimates that approximately 110.3 miles of trunk pipelines could be constructed. This would include medium and low-pressure trunk lines. The conceptual location of these pipelines is shown on Map 5. The gathering system would consist of buried pipelines up to 24 inches in diameter. For this analysis, regardless of pipe size, the gathering system would be constructed within a permanent corridor up to 60 feet wide.

1.5.7 Estimated Disturbance

The estimated disturbance associated with implementing the No Action Alternative is presented to allow comparative analysis and is based on the best available information. The actual amount of surface disturbance may vary from the estimated amount and would depend on site-specific proposals. The estimated amounts of short- and long-term disturbance per project component are listed in Table 1-6. Disturbance was estimated based on the following assumptions:

- 117 well pads at 18 acres per pad for construction and drilling; 10 acres per pad for operation
- 45 percent new well pads needing approximately 0.25-mile-long access road and well-connect pipeline constructed within a 40-foot-wide construction corridor reclaimed to a 30-foot-wide long-term corridor
- Fifteen off-site water storage facilities at 10 acres each
- 110.3 miles of trunk pipeline in a 60-foot-wide construction corridor

Table 1-6. No Action Alternative Estimated Short- and Long-term Disturbance

Component	Short-Term Disturbance (acres)	Long-Term Disturbance (acres)
Well pads	2,106	1,170
Access roads/well connect pipelines	64.2	48.2

Component	Short-Term Disturbance (acres)	Long-Term Disturbance (acres)
Off-site water storage	150	150
Permanent buried freshwater water line	N/A	N/A
Trunk pipelines	802.2	0
115-kilovolt power line	N/A	N/A
Substations	N/A	N/A
Compressor site	N/A	N/A
Total	2,972.4	1,218.2

Notes: N/A = not applicable

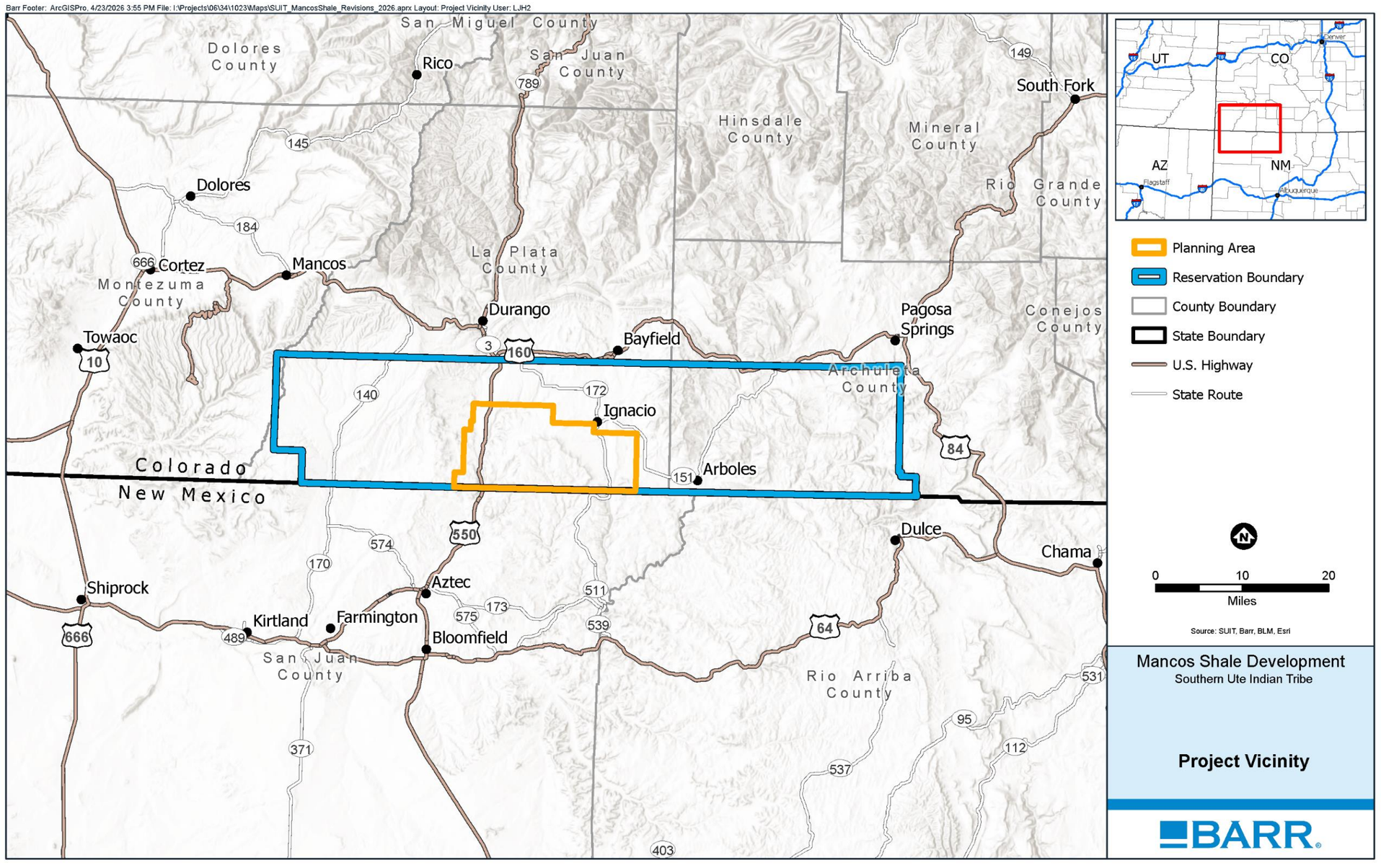
1.6 Comparison Between Alternatives

Table 1-7 provides a summary comparison of estimated surface disturbance between the alternatives.

Table 1-7. Summary of Estimated Disturbance Between the Proposed Action and No Action

Component	Proposed Action		No Action	
	Short-Term Disturbance (acres)	Long-Term Disturbance (acres)	Short-Term Disturbance (acres)	Long-Term Disturbance (acres)
Well pads	1,224	680	2,106	1,170
Access roads/well connect pipelines	17	13	64.2	48.2
Off-site water storage	60	60	150	150
Permanent buried waterline	145.5	0	N/A	N/A
Trunk pipelines	428.4	0	802.2	0
115-kilovolt power line	240	240	N/A	N/A
Substations	15	15	N/A	N/A
Compressor sites	10.5	10.5	N/A	N/A
Total	**2,140**	**1,018.5**	**2,972.4**	**1,218.2**

Note: NA = not applicable



Map 1. Mancos Shale Planning Area and Vicinity

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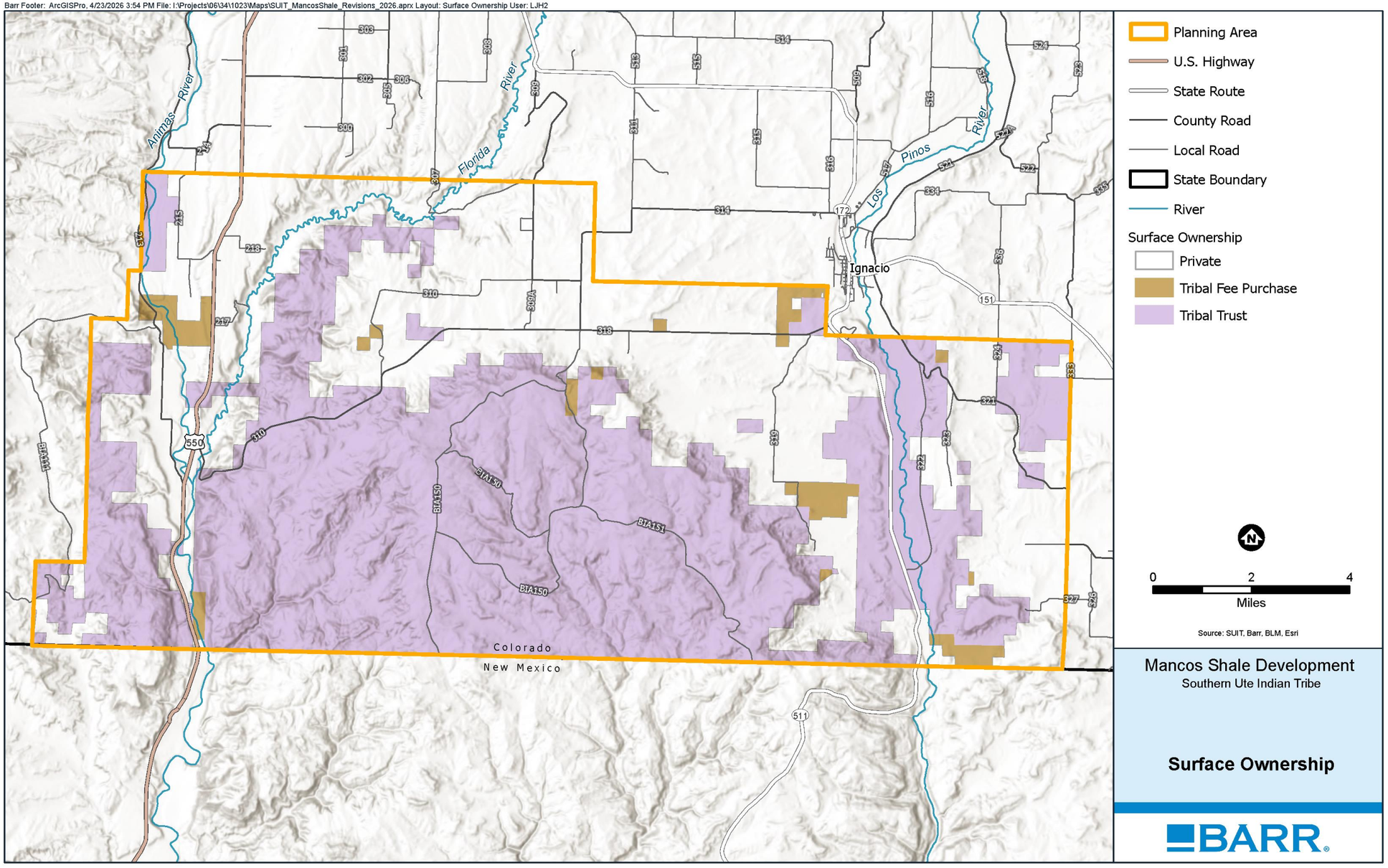
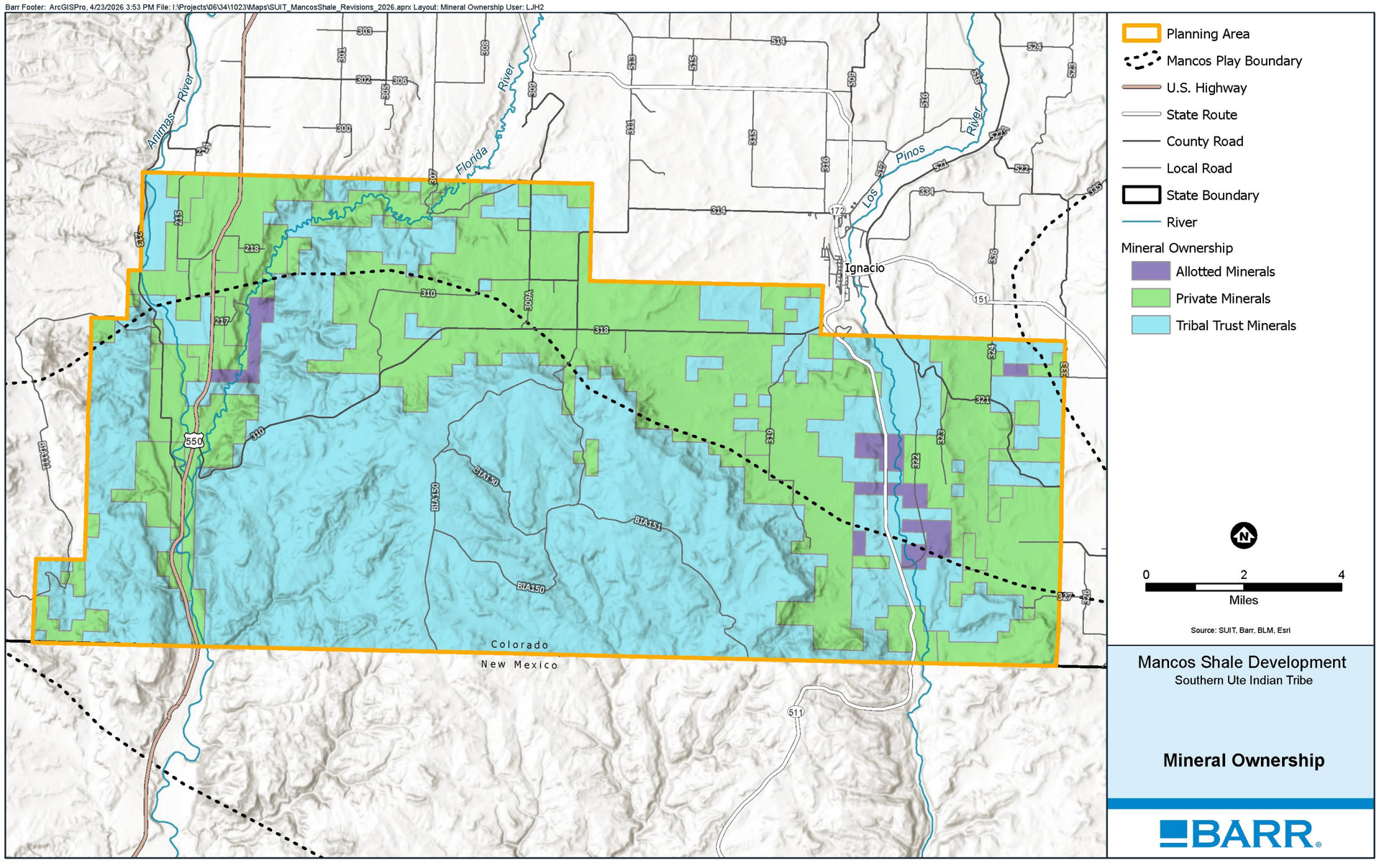


Map 2. Surface Ownership in the Planning Area



Map 3. Mineral Ownership in the Planning Area

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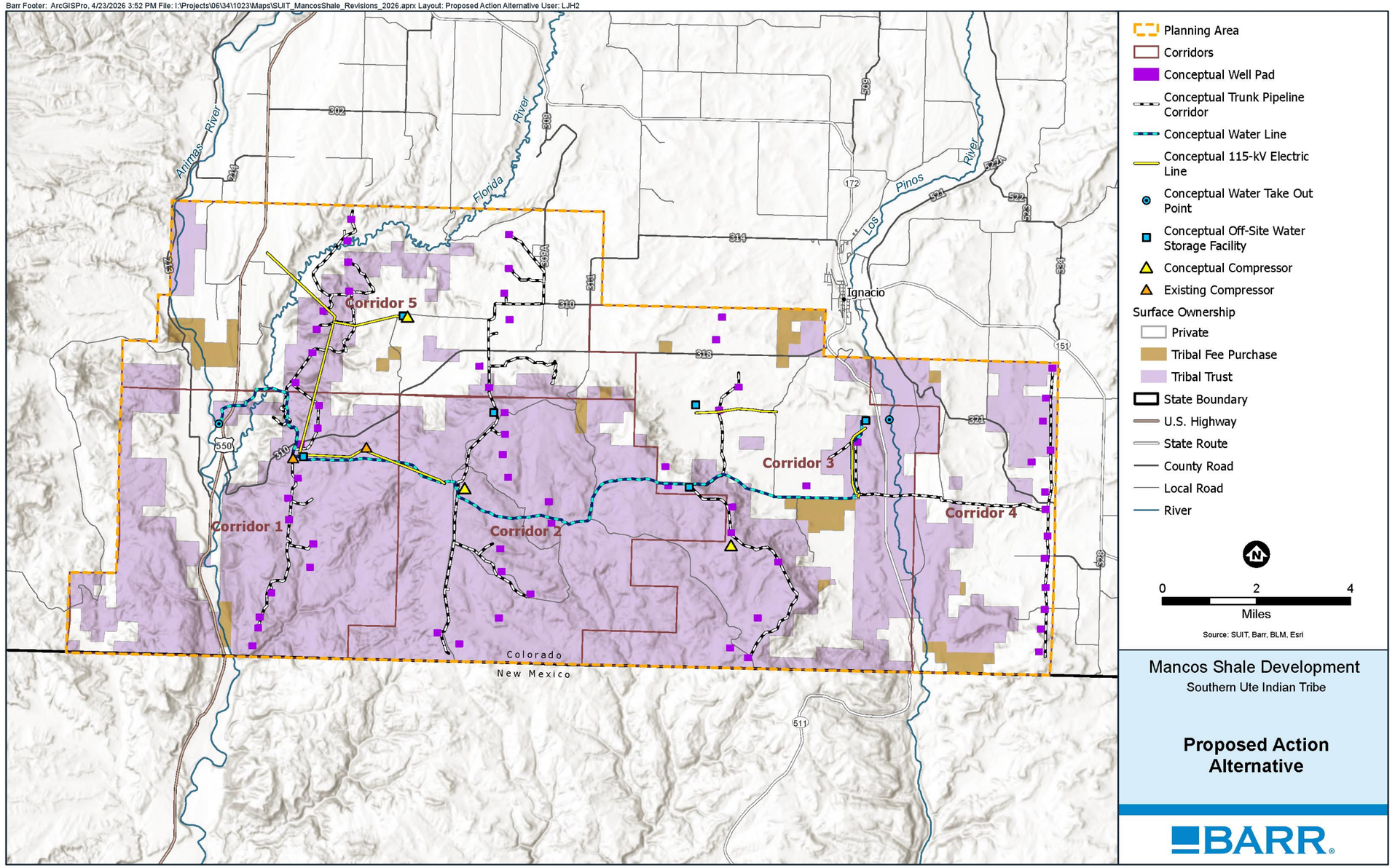

Map 4. Conceptual Proposed Action

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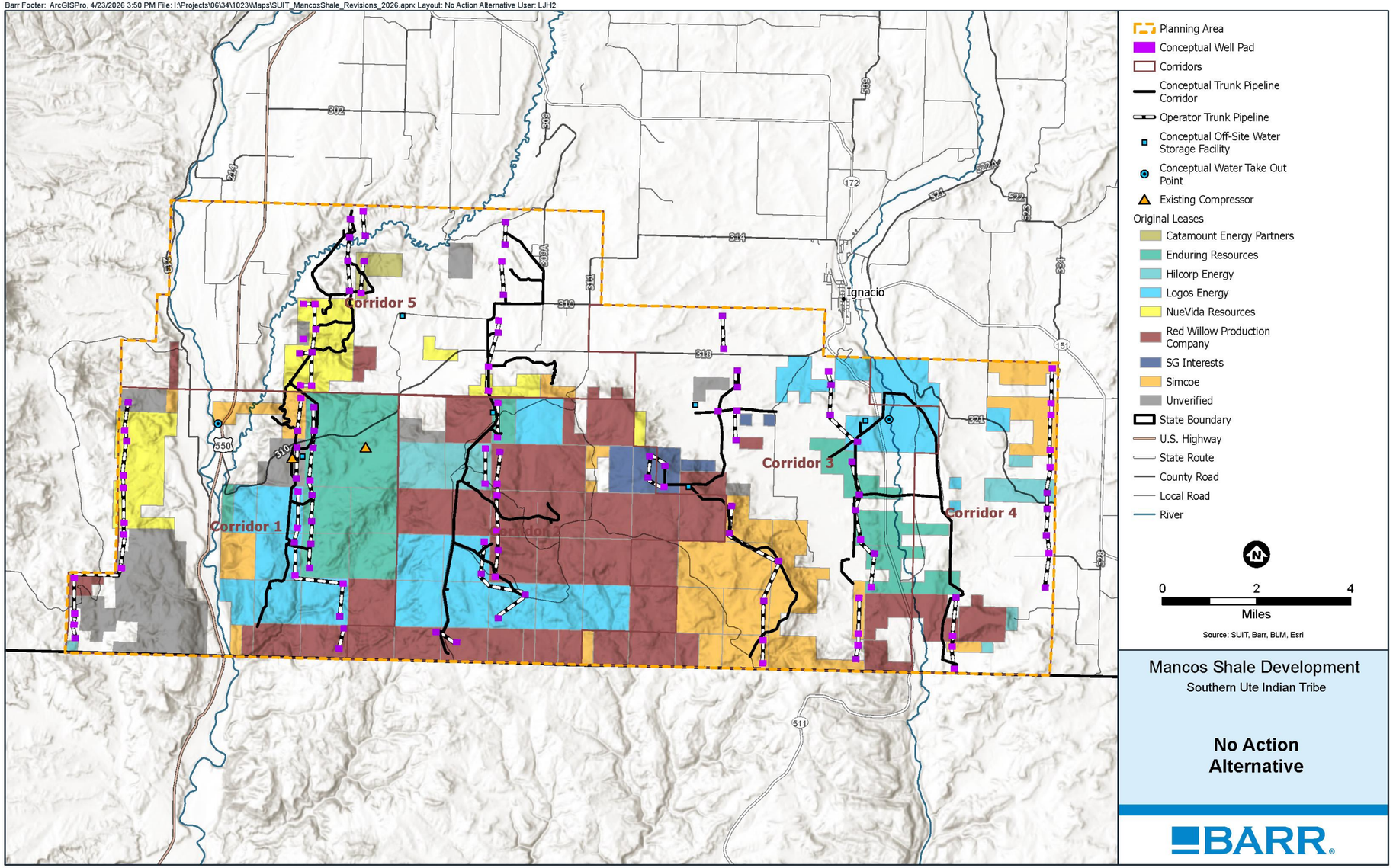

Map 5. Conceptual No Action