STATEMENT OF BASIS

Colowyo Coal Company, L.P.
(aka Tri-State Generation and Transmission Association, Inc.)
Colowyo Mine County Road 17 INJ#1
Moffat County, Colorado
Class V Non-Hazardous Waste Disposal Well
CO52432-12407

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This Statement of Basis gives the derivation of site-specific UIC permit conditions and reasons for them. Referenced sections and conditions correspond to sections and conditions in CO52432-12407 (Permit).

EPA UIC permits regulate the injection of fluids into underground injection wells so that the injection does not endanger underground sources of drinking water (USDWs). The EPA UIC permit conditions are based upon the authorities set forth in regulatory provisions at 40 CFR parts 2, 124, 144, 146 and 147, and address potential impacts to USDWs. In accordance with 40 CFR § 144.35, issuance of this Permit does not convey any property rights of any sort or any exclusive privilege, nor authorize injury to persons or property or invasion of other private rights, or any infringement of other federal, state or local laws or regulations. Under 40 CFR part 144 subparts D and E, certain conditions apply to all UIC Permits and may be incorporated either expressly or by reference. General permit conditions for which the content is mandatory and not subject to site-specific differences (40 CFR parts 144, 146 and 147) are not discussed in this document. Regulations specific to Colorado injection wells are found at 40 CFR part 147 subpart G.

Upon the Effective Date when issued, the Permit authorizes the construction and operation of injection well or wells so that the injection does not endanger USDWs. This Permit is issued for 10 (ten) years from the Effective Date, until it expires under the terms of the Permit, or unless modified, revoked and reissued, or terminated under 40 CFR §§ 124.5, 144.12, 144.39, 144.40 or 144.41.

PART I. General Information and Description of Project

Colowyo Coal Company, L.P. (aka Tri-State Generation and Transmission Association, Inc.)
P.O. Box 33695, 1100 W. 116th Avenue
Denver, Colorado 80233-0695

hereinafter referred to as the "Permittee," submitted an application for an Underground Injection Control (UIC) Program permit for the following injection well:

Colowyo Mine County Road 17 INJ#1
2225' FWL & 780' FNL, NWNW Section 23, T4N, R93W
Latitude: 40.307500, Longitude: -107.800446
Moffat County, Colorado

The application, including the required information and data necessary to issue or modify a UIC permit in accordance with 40 CFR parts 2, 124, 144, 146 and 147, was reviewed and determined by the EPA to be complete.

Project Description

Colowyo Coal Company, L.P. (Colowyo) is proposing to construct a new Class V deep injection well to dispose of East Taylor Spring water near County Road 17 in Moffat County, Colorado. Colowyo owns and operates the Colowyo Mine in Rio Blanco and Moffat Counties approximately 25 miles south of Craig, Colorado. A spring (East Taylor Spring) from reclaimed areas which were previously mined out and backfilled in the drainage upgradient of East Taylor Pond does not meet future Whole Effluent Toxicity (WET) limits for surface water discharge. Colowyo completed field testing and modeling of various climatological scenarios over a 100-year time frame determining that the maximum injection rate is projected to be 440 gpm with an annual average injection of 250 gpm. Colowyo intends to dispose of this spring flow via underground injection into a deep disposal well located approximately four (4) miles north of the spring location.

PART II. Permit Considerations (40 CFR § 146.14)

Hydrogeologic Setting

The Colowyo Coal Mine operation is located in the northern extent of the Danforth Hills coal field of the Uinta Region. The Danforth Hills field comprises the coal deposits on the northeast flank of the Piceance Creek Basin. The northeast flank is a northwest to southeast trending sub-basin of the Piceance Basin lying within the Collom Syncline location between the Axial Basin Anticline to the northeast and the Danforth Hills Anticline to the southwest.

The area is underlain by as much as 13,500 feet of sedimentary rock including the geologic units listed in Table 1. Based on the *Geologic Map of the Axial Quadrangle, Moffat and Rio Blanco Counties, Colorado*[1] and the associated cross section, INJ#1 occurs at a location where the Wilson Creek alluvium occurs at the surface, underlain by the Mancos Shale. The Meeker Sandstone Member of the Mancos Shale occurs at an estimated depth of 1,200 feet below the top of the Mancos Shale at the well site. Formation depths of the underlying geologic units are estimated from the logs of nearby oil and gas wells available in the Colorado Energy and Carbon Management Commission database and shallow

[1] John K. Hardie and Jonathan M. Zook, 2014, Geologic Map of the Axial Quadrangle, Moffat and Rio Blanco Counties, Colorado, OFR 14-08, https://coloradogeologicalsurvey.org/publications/geologic-map-axial-quadrangle-moffat-rio-blanco-colorado/.

well logs from the Division of Water Resources database. Actual formation depths will be determined by logging the injection well drill hole.

TABLE 1
Geologic Setting

Formation Name or Stratigraphic Unit	Top (ft)*	Base (ft)*	TDS (mg/l)	Potential USDW?	Lithology
Wilson Creek alluvium	0	30	unknown	Y	Sandy silt, silty clay
Mancos Shale	30	4174	1,368†	N	Shale
Meeker Member	1270	1460		Y	Sandstone
Dakota Sandstone	4174	4774	6,825-37,206‡	Y	Sandstone
Entrada Sandstone Kayenta Formation Wingate Sandstone	4774	5124	unknown	Y	Sandstone
Chinle Formation	5124	5490	unknown	N	Shale and siltstone
Shinarump Member	5490	5674	unknown	Y	Sandstone and conglomerate
Moenkopi Formation	5674	6174	n/a	Y	Interbedded shales, siltstone, and siliceous dolomites
Park City Formation	**	**	n/a	n/a	Carbonate
Weber Sandstone	6174	6544	unknown	Y	Sandstone
Maroon Formation	6544	7128	unknown	N	Sandstone, siltstone, conglomerate, evaporites and local limestone.
Morgan-Minturn Formations	7128	7428	unknown	Y	Sandstone, siltstone, conglomerate, and local limestone.
Belden Formation	7428	**	n/a	N	Shale
Molas Formation	**	**	n/a	N	Silty, variegated shale with chert or limestone nodules, siltstone, and limestone[2]
Leadville Limestone	**	**	n/a	N	Limestone, dolomite

[2] Armstrong, A.K., Mamet, B.L., and Repetski, J.E., 1992, Stratigraphy of the Mississippian System, south-central Colorado and north-central New Mexico, USGS Bulletin, 1787-EE, at EE13. https://pubs.usgs.gov/bul/1787ee/report.pdf.

Undifferentiated Pre-Carboniferous sediments	**	**	n/a	Y	Marine black shale, sandstones, and limestones

*Depths are estimated from formation tops identified in nearby wells. Actual depths at the injection well will be based on well logs.

** Not identified in the nearby well logs.

[†] TDS from a single sample taken from the "B" sandstone (Prairie Canyon Member equivalent to Meeker) of the Mancos Shale in the Piceance Basin reported in the USGS Produced Water Database v2.3.

[‡] TDS presented as Q1 to Q3 quartile range for 61 samples from the Piceance Basin reported in the USGS Produced Water Database v2.3 with a median TDS concentration of 9,726 mg/L.

Injection Zone

An injection zone is a geological formation, group of formations, or part of a formation that receives fluids through a well. The proposed injection zone formations are listed in TABLE 2. The proposed Class V well is estimated to be 7,428 feet deep and will inject into permeable intervals within the Triassic Moenkopi and the Shinarump (basal) Member of the Chinle Formations, the Lower Permian Weber Sandstone, the Pennsylvanian Maroon, and Morgan-Minturn Formations listed in Table 1. Lithologic, gamma ray, spontaneous potential (SP), resistivity, and porosity geophysical logs from the nearby wells which penetrate the proposed injection zone were used to identify permeable intervals within an approximate 1,938-foot-thick interval that includes the geologic units in Table 2. Based on density-porosity and sonic-porosity logs from the Jensen Federal 1-33 well, porosity for these zones is estimated to be approximately 12% for the Shinarump Formation, 5% in the Moenkopi Formation, 16% in the Weber Sandstone. Based on sonic porosity logs from well Pioneer Federal #1, porosity for the upper sandstone in the Minturn Formation is estimated to be 10%.

TABLE 2
INJECTION ZONE

Formation Name or Stratigraphic Unit	Top (ft)*	Base (ft)*
Non-USDW Triassic-Jurassic Aquifers: Entrada Sandstone Kayenta Formation Wingate Sandstone	4774	5124
Shinarump	5,490	5,674
Moenkopi	5,674	6,174
Weber	6,174	6,544
Maroon	6,544	7,128
Morgan-Minturn	7,128	7,428

* Depths are estimated from formation tops identified in nearby wells. Actual depths will be based on well logs.

The injection zone stratigraphy is described in several publications with different interpretations as to name assignments. For clarity and ease of reference, the EPA is using the nomenclature and interpretation from *Column E-Piceance Basin* in Marjorie E. MacLachlan, 1981, *Stratigraphic Correlation Chart for Western Colorado and Northwestern New Mexico* (Figure 1). This stratigraphic column shows the relationship between sandstone and confining units that the Permittee will investigate as potential injection zone aquifers.

In addition, the Permittee plans to collect groundwater samples from the Triassic and Jurassic sandstones shown in Figure 1 to determine if aquifer fluids have a total dissolved solids concentration (TDS) greater than or equal to 10,000 mg/L. If an aquifer has a TDS concentration greater than or equal to 10,000 mg/L, it does not meet the definition of USDW, and the Permittee may consider it for use as an injection zone. TDS analysis includes analysis of the major anions and cations listed in Permit Appendix IV, Table IV-2 to allow for quality control evaluation of TDS results. The EPA will review the water quality and log information submitted by the Permittee described in Attachment IV of the Permit. The EPA will approve authorization to inject into proposed injection zones that are not USDWs and have adequate overlying and underlying confining zones to prevent injection zone fluids from migrating into USDWs. The Permit does not allow injection into a USDW.

The Permittee may decide to analyze samples from each aquifer listed in Table 2 for Total and Dissolved Metals, Fluoride and Gross Alpha, because the Permittee may decide to submit a future request for a major modification of this draft Permit, if issued as final, proposing the use of an aquifer that is a USDW as an injection zone. The purpose for analyzing these additional parameters is to determine permit limits for a potential USDW injection zone. A major modification of the Permit requires issuance of a draft permit and public comment period. If a future permit allows injection into a USDW, the permit would require quarterly sampling and analyzing samples for fluoride and total metals present in the injectate at detectable concentrations.

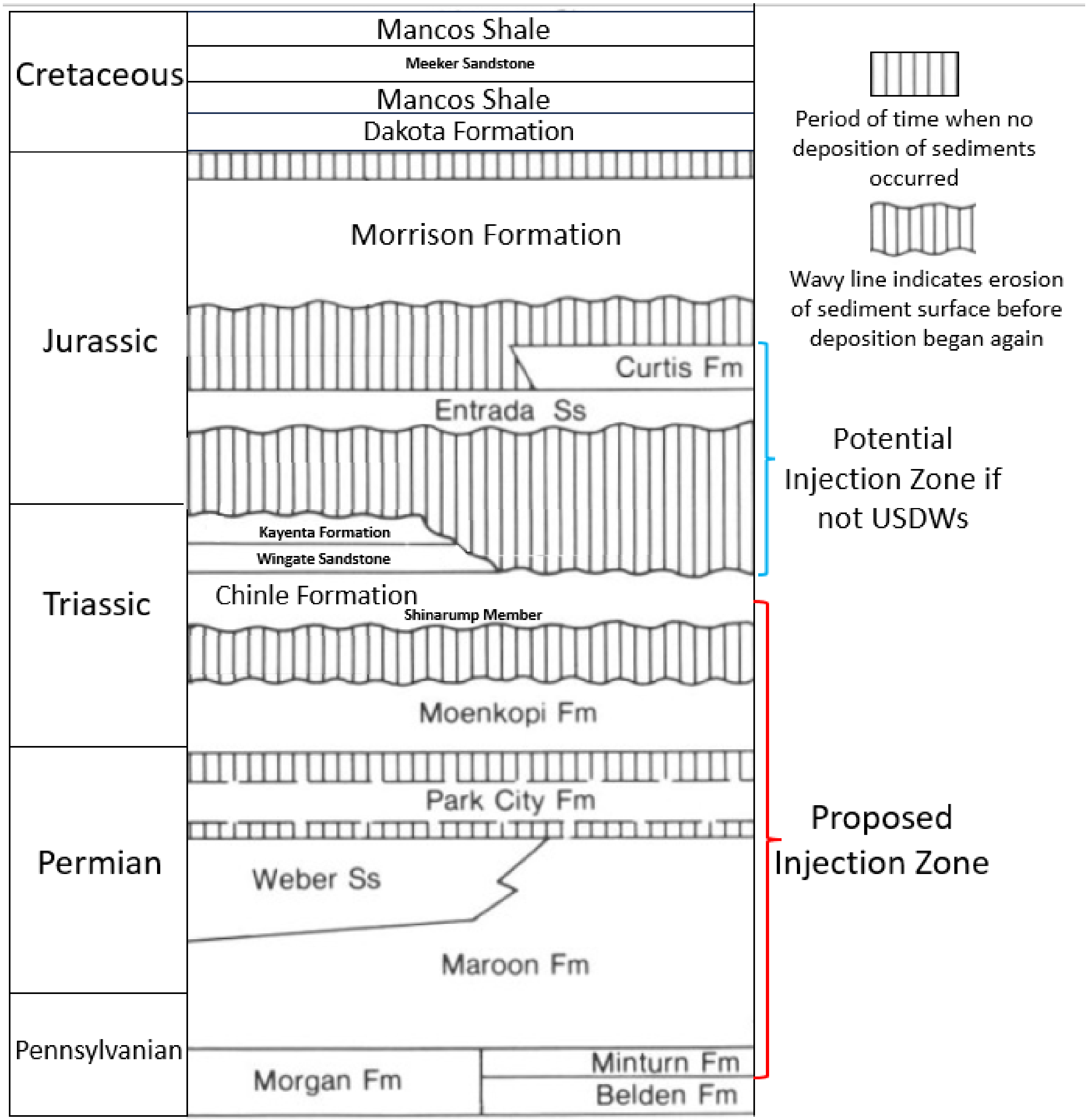


Figure 1. Injection Zone and Overlying Formations (adapted from MacLachlan, 1981[3])

[3] Marjorie E. MacLachlan, 1981, *Stratigraphic Correlation Chart for Western Colorado and Northwestern New Mexico*. https://nmgs.nmt.edu/publications/guidebooks/downloads/32/32_p0075_p0079.pdf.

Confining Zones

A confining zone is a geological formation, part of a formation, or a group of formations that limits fluid movement above and below the injection zone. The overlying and underlying confining zones are listed in TABLES 3A and 3B.

At the INJ#1 location, the overlying confining zone is approximately 170 feet of Chinle Formation consisting of shales, siltstone, fine to very fine-grained sandstone, and occasional interbedded limestone. The lower confining interval consists of over 1,000 feet of shales, shaly sandstones, and carbonates below the base of the Morgan-Minturn injection zone. The geologic formation name to which the underlying confining zone belong varies among publications and well logs. In Table 3A the lower confining zone is identified as basal Morgan Formation/Belden Shale.

TABLE 3A
CONFINING ZONES

Confining Zone	Formation Name or Stratigraphic Unit	Top (ft) *	Base (ft) *	Lithology
Upper	Chinle Formation	5,124	5,490	Shale and siltstone
Lower	Basal Morgan Formation/Belden Shale **	7428	--	Shale***

* Depths are estimated from formation tops identified in nearby wells. Actual depths will be based on well logs.
** MacLachlan, 1981, Column E.
*** Brill, Jr., 1944[4]

If groundwater samples from the Triassic Kayenta and Wingate Sandstones or the Jurassic Entrada Sandstone show any of these units are not USDWs, the Permittee may propose them to the EPA as potential injection zones. In this case the Morrison Formation and the Chinle Formation shown in Table 3B will be the overlying and underlying confining zones, respectively.

TABLE 3B
CONFINING ZONES

Confining Zone	Formation Name or Stratigraphic Unit	Top (ft) *	Base (ft) *	Lithology
Upper	Morrison	2,998	3,456	Shale and claystone
Lower	Chinle Formation	5,124	5,490	Shale and siltstone

* Depths are estimated from formation tops identified in nearby wells. Actual depths will be based on well logs.

The Curtis Formation has been mapped in western Moffat County and has been identified in some nearby well logs; however, it is not clear from available geologic references that this formation will be present at the injection well site. If present, the Curtis Formation may contain sandstone layers that may be evaluated as potential injection zones.

[4] Kenneth G. Brill, Jr., 1944, Late Paleozoic Stratigraphy, West-Central and Northwestern Colorado, Bulletin of the Geological Society of America, Vol. 55, No. 5. https://pubs.geoscienceworld.org/gsa/gsabulletin/article-abstract/55/5/621/4043/Late-Paleozoic-stratigraphy-west-central-and?redirectedFrom=fulltext.

Underground Sources of Drinking Water (USDWs)

Aquifers or the portions thereof which 1) currently supply any public water system or 2) contain a sufficient quantity of groundwater to supply a public water system and currently supply drinking water for human consumption or contain fewer than 10,000 mg/l TDS are considered to be USDWs.

The main geologic formations which serve as groundwater sources in the sub-basin for drinking water, irrigation, and industrial use are the Quaternary alluvial aquifers, the Miocene Browns Park Formation, the Upper Cretaceous Iles Formation sandstones and Williams Fork Formation of the Mesa Verde Group. At the Colowyo Mine County Road 17 INJ#1 (hereinafter INJ#1) well location, the surface formation is the Williams Fork alluvium overlying the Cretaceous Mancos Shale. Based on the INJ# on the map in Plate 1 and within the cross section in Plate 2 of the *Geologic Map of the Axial Quadrangle, Moffat and Rio Blanco Counties, Colorado*,[5] except for the alluvium, none of these formations are present at the proposed injection well location, although an outcrop of the Browns Park is located not far away from the well location in Sections 14 and 23, T4N, R932W. The cemented surface casing and cement of the INJ#1 must extend 50 feet below the base the Meeker Sandstone Member of the Mancos Formation per 40 CFR part 147, subpart G-Colorado § 147.305 (d)(1)(i).

Several sandstones beneath the Mancos Formation are potential USDWs, including the Upper Cretaceous Dakota Group and the Jurassic Entrada Sandstone. The nearest potential USDWs overlying the injection zone are the Triassic sandstones of the Kayenta and Wingate Formations. Some aquifers within the injection zone are potential USDWs. The Upper Triassic Shinarump Member of the Chinle Formation, and the Pennsylvanian Weber Sandstone have been granted EPA aquifer exemptions in Moffat and Rio Blanco counties and thus, may be USDWs in the sub-basin. Because of the presence of potential USDWs underlying the injection zone in this area, the requirement for Class I wells that the injection zone must lie beneath the lowermost USDW within one-quarter mile of the well bore per 40 CFR 144.6(a) may not be met. For this reason, INJ#1 is Class V instead of Class I. However, the Permittee has proposed, and the Permit requires, protective Class I well construction standards and protection of all USDWs by cementing the outmost casing and verifying confining zones from well logs.

PART III. Well Construction (40 CFR § 146.12)

The minimum well construction requirements are included in Attachment I of the permit. The proposed well construction plan meets these requirements and is also included in Attachment I. Modification of the proposed plan during construction is allowed under 40 CFR § 144.52(a)(1) provided written approval is obtained from the Director prior to actual modification.

Casing and Cement

The well construction plan was evaluated and determined to be in conformance with standard practices and guidelines that ensure well injection does not result in the movement of fluid containing any contaminant into USDWs. Well construction details for the injection well(s) are shown in TABLE 4. To protect shallow USDWs when drilling the surface hole, the Permittee is limited to drilling with air or mud made with water containing no additives and no more than 3,000 mg/l TDS, unless waived by the Director.

[5] Hardie, J.K. and Zook, J.M., 2014, Geologic Map of the Axial Quadrangle, Moffat and Rio Blanco Counties, Colorado, Open-File Report 14-08, Plate 2. Colorado Geological Survey and the Colorado School of Mines. https://coloradogeologicalsurvey.org/publications/geologic-map-axial-quadrangle-moffat-rio-blanco-colorado/

Remedial cementing may be required if the casing cement is shown to be inadequate by cement bond log or other demonstration of external (Part II) mechanical integrity.

TABLE 4
WELL CONSTRUCTION INFORMATION

Casing Type	Hole Size (in)	Casing Size (in)	Cased Interval (ft)*	Cemented Interval (ft)*
36# JSS surface casing	12 ¼ in	9 5/8 in	0-1270	0-1300
26# HCP 110	8 ¾	7 in	0-7428	0-7428
Coated EUE Injection Tubing	NA	3 ½ in	0-5490	NA

* Depths are estimated from formation tops identified in nearby wells. Actual depths will be based on well logs.

Well Siting

Class V deep wells inject non-hazardous fluids into or above USDWs sources of drinking water. The EPA has reviewed information provided by the Permittee in the permit application regarding the confining zones and the extent of nearby faults and has determined the location of the proposed injection well will allow for the proposed injection operations to occur without endangerment to USDWs in the area.

Injection Tubing and Packer

Injection tubing is required to be installed from a packer up to the surface inside the well casing. The packer must be set within 100 feet above the uppermost perforation. The tubing and packer are designed to prevent injection fluid from coming into contact with the production casing.

Tubing-Casing Annulus

The tubing-casing annulus (TCA) allows the casing, tubing and packer to be pressure-tested periodically for mechanical integrity and will allow for detection of leaks. The TCA will be filled with non-corrosive fluid or other fluid approved by the Director.

Sampling and Monitoring Devices

To fulfill permit monitoring requirements and provide access for EPA inspections, sampling and monitoring equipment will need to be installed and maintained. Required equipment includes but is not limited to: 1) pressure actuated shut-off device attached to the injection flow line set to shut-off the injection pump when or before the MAIP is reached at the wellhead; 2) fittings or pressure gauges attached to the injection tubing(s), TCA; 3) a fluid sampling point between the pump house or storage tanks and the injection well, isolated by shut-off valves, for sampling the injected fluid; 4) a flow meter capable of recording instantaneous flow rate and cumulative volume attached to the injection line; and 5) continuous recording devices to monitor injection pressure, flow rate, volume, pressure on the annulus between the tubing and the long string of casing, and pressure on the bradenhead annulus in between the surface and long string casing.

All sampling and measurement taken for monitoring must be representative of the monitored activity.

Well Injection and Seismicity

The Permit requires seismic monitoring of the area surrounding the proposed injection well. The U.S. Geological Survey (USGS) Earthquake Hazards Program operates an email notification service known as the Earthquake Notification Service (ENS), which reports real-time earthquake events for any area specified by the user. Details for the ENS can be found at: https://earthquake.usgs.gov/ens/. The Permit requires the Permittee to subscribe to this service and check daily for notification emails from the service If an event measuring 4.5 magnitude (MMI scale) or greater is detected within two (2) miles of the wellbore, the Permittee will immediately cease injection and report the event to the EPA within 24 hours. The Permittee will report all seismic events measuring 2.0 magnitude on the Modified Mercalli Intensity (MMI) scale or greater within 50 miles radius of the wellbore and provide a summary of the seismic events in the semiannual reports.

PART IV. Area of Review, Corrective Action Plan (40 CFR § 144.55)

Area of Review (AOR)

Permit applicants are required to identify the location of all known wells within the AOR which penetrate the lowermost confining zone, which is intended to inhibit injection fluids from the injection zone. Under 40 CFR § 146.6 the AOR may be a fixed radius of not less than one quarter (1/4) mile or a calculated zone of endangering influence.

The area of review for this permit is a fixed-radius of 2.25 miles based on hydrogeologic factors calculated using the modified Theis. Site specific parameters used in the modified Theis for Zone of Endangering Influence (ZEI) methods were estimated from detailed lithologic logs, geophysical logs, and drill stem test data in Colorado Energy and Carbon Management Commission database from the three nearby oil and gas wells discussed above. See Attachment A2 found in the Area of Review Size Determination of the Permit application for a description of the AOR calculation.

Corrective Action Plan (CAP)

For wells in the AOR which are improperly sealed, completed, or abandoned, the applicant will develop a CAP consisting of the steps or modifications that are necessary to prevent movement of fluid into USDWs.

No corrective action is required at this time as the EPA's evaluation did not identify migration pathways that would impact USDWs within the area of review.

PART V. Well Operation Requirements (40 CFR § 146.13)

Mechanical Integrity (40 CFR § 146.8)

An injection well has mechanical integrity (MI) if:

1. Internal (Part I) MI: there is no significant leak in the casing, tubing, or packer; and
2. External (Part II) MI: there is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore.

The Permit requires MI to be maintained at all times. The Permittee must demonstrate MI prior to receiving authorization to inject and periodically thereafter, as required in Attachment III – Monitoring and Reporting Requirements and Attachment V - Logging and Testing Requirements. A demonstration of well MI includes both internal (Part I) and external (Part II). The methods and frequency for demonstrating Part I and Part II MI are dependent upon well and are subject to change. Should well conditions change during the operating life of the well, additional requirements may be specified and will be incorporated as minor modifications to the Permit.

A successful internal Part I Mechanical Integrity Test (MIT) is required prior to issuance of authorization to inject and repeated no less than five years after the last successful MIT. A demonstration of internal MI is also required following any workover operation that affects the tubing, packer, or casing or after a loss of MI. In such cases, the Permittee must complete work and restore MI within 90 days following the workover or within the timeframe of the approved alternative schedule. After the well has lost mechanical integrity, injection may not recommence until after internal MI has been demonstrated and the Director has provided written approval.

Part I MI is demonstrated by using the maximum permitted injection pressure or 1,000 psi, whichever is less, with a ten percent or less pressure loss over thirty minutes. Additional guidance for Part I MI can be found at https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy#guidance.

Part II MI will be required prior to issuance of authorization to inject and repeated no less than five (5) years after the last successful MIT. Part II MI will be demonstrated by using the results of the required radioactive tracer survey, prior to authorization to inject, and after receiving authorization to inject Part II MI will be demonstrated by temperature logging. Guidance on radioactive tracer surveys and temperature logging can be found at https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy#guidance.

Injection Fluid Limitation

The Permit authorizes the injection of only the non-hazardous fluids naturally flowing from the East Taylor Spring.

Volume Limitation

There is no limitation on the fluid volume permitted to be injected into this well. In no case is the injection pressure allowed to exceed the Maximum Allowable Injection Pressure (MAIP).

Injection Pressure Limitation

40 CFR § 146.13(a)(1) requires that the injection pressure at the wellhead must not exceed a maximum calculated to ensure that the pressure during injection does not initiate new fractures or propagate existing fractures in the injection zone.

The calculated MAIP described below is the pressure that will initiate fractures in the injection zone and that the Director has determined satisfies the above condition. Except during stimulation, the injection pressure must not exceed the MAIP. Furthermore, under no circumstances must injection pressure cause the movement of injection or formation fluids into a USDW.

The **MAIP** allowed under the Permit, as measured at the surface, will be calculated according to the equations below. The Permit itself does not contain a specific MAIP value but instead requires that a MAIP be calculated using these equations. The Permit also specifies where the input values are derived from. Prior to authorization to commence injection, the Permittee must submit for review the necessary information to calculate the MAIP. After review of the submitted documents, the Director will notify the Permittee of the MAIP in the written authorization to commence injection.

The formation fracture pressure (**FP**) is the pressure above which injection of fluids will cause the rock formation to fracture. This equation, as measured at the surface, is defined as:

$$\mathbf{FP} = [\mathbf{FG} - (0.433 * (\mathbf{SG} + 0.05))] * \mathbf{D}$$

Where, FG is the fracture gradient in psi/ft

SG is the specific gravity

D is the depth of the top perforation in feet

The **FG** value for each well will be determined by conducting a step rate test. The results of the test will be reviewed and approved by the Director. As appropriate, the FG may be determined by one of these other following methods:

- Representative **FG** values determined previously from valid tests in nearby wells.
- Established **FG** values found in reliable sources approved by the Director. These could include journal articles, scientific studies, etc.
- An alternative method approved by the Director.

The value for **SG** must be obtained from the fluid analysis of a representative sample of the injection fluid.

The value for **D** is the depth of the top perforation of the as-built well.

When a step rate test is conducted, bottom-hole and surface gauges are required. This requirement may be waived by the Director but may result in a final MAIP that does not include adjustment for friction loss.

The MAIP can also be adjusted for friction loss if the friction loss can be adequately demonstrated. To account for friction loss, the **MAIP** is equal to **FP** adjusted for friction loss, or:

MAIP = **FP** + friction loss (if applicable)

An acceptable method to determine friction loss is to measure it directly. Friction can be calculated when surface and bottom-hole pressures are known. When conducting a step rate test, a surface and bottom-hole gauge at depth **D** are necessary to calculate friction loss.

During the operational life of the well, the depth to the top perforation, fracture gradient, and specific gravity may change. When well workover records, tests, or monitoring reports indicate one of the variables in the FP equation has changed, the MAIP calculation will be reviewed. The EPA is incorporating the MAIP equations into this Permit instead of identifying a specific MAIP value because it will result in a more efficient application of the true MAIP, as these changes occur over the life of the well to provide greater protection for nearby USDWs.

When additional perforations to the injection zone are added, the Permittee must provide the appropriate workover records and also demonstrate that the fracture gradient value to be used is representative of the portion of the injection interval proposed for perforation. It may be necessary to run a step rate test to provide representative data, such as when a new formation (within the approved injection zone) or a geologically distinct interval (based on core data or well logs) in the same formation is proposed for injection.

When the fracture gradient or depth to top perforation changes, the formation fracture pressure will be recalculated. The Permittee will also submit fluid analysis that reports SG semiannually. In the above, a factor of 0.05 has been added to the SG. This adjustment factor allows for the MAIP to be recalculated only if the newly submitted SG is greater than 0.05 from the previous year's SG, without exceeding the fracture pressure of the formation. A MAIP due to the SG change will only be recalculated if the absolute difference of the newly submitted SG and that of the previous year is greater than 0.05.

The new permitted MAIP will become effective when the Director has provided written notification. The Permittee may also request a change to the MAIP by submitting the necessary documentation to support a recalculation of the MAIP.

As discussed above, the formation fracture pressure calculation sets the MAIP to assure that the pressure used during injection does not initiate new fractures or propagate existing fractures in the injection zone(s). However, it may be that the condition of the well may also limit the permitted MAIP. When Part II MI demonstrations (such as a temperature survey or radioactive tracer test) are required, the tests required to make this demonstration must be conducted at the permitted MAIP based on the calculations described above. If during testing, the Permittee is unable to achieve the pressure at the permitted MAIP, the new permitted MAIP will be set at the highest pressure achieved during a successful Part II MI and not the calculated MAIP.

PART VI. Monitoring, Recordkeeping and Reporting Requirements

Injection Well Monitoring Program

Continuous monitoring of injection pressure, injection flow rate, injection volume, cumulative fluid volume, and TCA and bradenhead pressures must be conducted at the wellhead. If the continuous monitoring is conducted with digital equipment, the instrumentation must be capable of recording at least one value for each of the parameters at least every thirty (30) seconds. If the continuous monitoring is conducted with a continuous chart recorder: 1) to monitor the injection, and annulus, the chart must be of a scale that allows changes in pressure of five (5) psi to be detected and; 2) to monitor the injection volume and injection rate the chart must be of a scale that allows changes in pressure of 5 barrels or barrels per day to be detected. Monthly averaged, maximum, and minimum values for injection pressure, flow rate and volume, and annular pressure is required to be reported as part of the Semiannual Report to the Director.

Injectate Monitoring Requirements (If the Injection Zone is a USDW)

Attachment V of the Permit requires the Permittee to collect and analyze a representative sample of the injectate twice a year: one during the high-flow season for the East Taylor spring (September/October) and one during the low-flow season (January/February). Samples must be analyzed for parameters listed in Attachment III of the Permit. The purpose of these analyses is to determine if there is seasonal variation in these two parameters. Specific gravity of the injectate affects the injection pressure.

Reporting Requirements

Permittee must submit semiannual monitoring reports to the EPA that include all the monitoring requirements specified in Attachment III of the Permit. Monitored parameters that must be reported include injectate parameters listed in Attachment III of the Permit; monthly minimum, maximum and averaged values for injection pressure, injection flow rate, and TCA pressure; maximum and minimum bradenhead pressure; and monthly injected volume and cumulative volume. The results of any MITs conducted during the reporting period, a summary of seismic monitoring, and information about any new AOR wells must also be included in the semiannual reports to the Director.

PART VII. Plugging and Abandonment Requirements (40 CFR § 146.10)

Plugging and Abandonment Plan

Prior to abandonment, the well must be plugged in a manner that isolates the injection zone and prevents movement of fluid into or between USDWs, and in accordance with any applicable federal, state or local law or regulation. Tubing, packer and other downhole apparatus must be removed. Cement with additives such as accelerators and retarders that control or enhance cement properties may be used for plugs; however, volume-extending additives and gel cements are not approved for plug use. Plug placement must be verified by tagging. A minimum 50 ft. surface plug must be set inside and outside of the surface casing to seal pathways for fluid migration into the subsurface.

The Permit requires the Permittee to analyze the water quality of all aquifers below the Meeker Sandstone and isolate USDWs from each other with a plug within the wellbore if there is more than 2,000 mg/liter difference in TDS between individual exposed USDWs.

Within thirty (30) days after plugging the owner or operator must submit Plugging Record (EPA Form 7520-19) to the Director. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. The plugging and abandonment plan is described in Attachment VI of the Permit.

PART VIII. Financial Responsibility (40 CFR § 144.52(a)(7))

1. Method of Providing Financial Responsibility

The Permittee, including the transferor of a permit, is required to demonstrate and maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director until:

- The well has been plugged and abandoned in accordance with an approved plugging and abandonment plan pursuant to 40 CFR §§144.51(o) and 146.10, and the permittee has submitted a plugging and abandonment report pursuant to 40 CFR §144.51(p); or
- The well has been converted in compliance with the requirements of 40 CFR §144.51(n); or
- The transferor of a permit has received notice from the Director that the owner or operator receiving transfer of the permit, the new permittee, has demonstrated financial responsibility for the well.

No substitution of a demonstration of financial responsibility must become effective until the Permittee receives notification from the Director that the alternative demonstration of financial responsibility is acceptable. The Director may, on a periodic basis, require the holder of a permit to revise the estimate of the resources needed to plug and abandon the well to reflect changes in such costs and may require the Permittee to provide a revised demonstration of financial responsibility.

2. Types of Adequate Financial Responsibility.

Adequate financial responsibility to properly plug and abandon injection wells under the Federal UIC requirements must include completed original versions of one of the following:

(a) a surety bond with a standby trust agreement,

(b) a letter of credit with a standby trust agreement,

(c) a fully funded trust agreement, or

(d) a financial test and corporate guarantee.

A surety bond acceptable to the Director must contain wording identical to model language provided to the permittee by the EPA and must be issued by a surety bonding company found to be acceptable to the U.S. Department of Treasury, which can be determined by review of that Department's Circular #570, currently available on the internet at: https://www.fiscal.treasury.gov/fsreports/ref/suretyBnd/c570.htm.

A letter of credit acceptable to the Director must contain wording identical to model language provided to the permittee by the EPA (40 CFR 144.70) and be issued by a bank or other institution whose operations are regulated and examined by a State or Federal agency.

A fully funded trust agreement acceptable to the Director must contain wording identical to model language provided to the permittee by the EPA. Annual reports from the financial institution managing the trust account must be submitted to the Director showing the available account balance.

An independently audited financial test with a corporate guarantee acceptable to the Director must contain wording identical to model language provided to the permittee by the EPA and must demonstrate that the Permittee meets or exceeds certain financial ratios. The Permittee must meet the EPA's requirements including, but not limited to, total net worth to be able to use this method. If this financial instrument is used, it must be resubmitted annually, within 90 days after the close of the Permittee's fiscal year, using the financial data available from the most recent fiscal year. If at any time the Permittee does not meet the financial ratios, notice to the EPA must be provided within 90 days and a new demonstration of financial responsibility must be submitted within 120 days.

The Permittee must submit a completed, originally signed financial responsibility demonstration to:

UIC Financial Responsibility Coordinator
Mail Code: 8ENF-ROR
U.S. Environmental Protection Agency
1595 Wynkoop Street
Denver, Colorado 80202-1129

3. Determining How Much Coverage is Needed

The Permittee, when periodically requested to revise the plugging and abandonment cost estimate discussed above, may be required to adjust the given cost for inflation or pursue a new cost estimate as prescribed by the Director.

4. Insolvency

In the event of:

(a) the bankruptcy of the trustee or issuing institution of the financial mechanism;

(b) suspension or revocation of the authority of the trustee institution to act as trustee; or

(c) the institution issuing the financial mechanism losing its authority to issue such an instrument,

the Permittee must notify the Director in writing, within ten (10) business days, and the Permittee must establish other financial assurance or liability coverage acceptable to the Director within sixty (60) calendar days after any event specified in (a), (b), or (c) above.

The Permittee must also notify the Director by certified mail of the commencement of voluntary or involuntary proceedings under Title 11 (Bankruptcy), U.S. Code naming the owner or operator as debtor, within ten (10) business days after the commencement of the proceeding. A guarantor, if named as debtor of a corporate guarantee, must make such a notification as required under the terms of the guarantee.

PART IX. Considerations Under Other Federal Law (40 CFR § 144.4)

The EPA will ensure that issuance of this Permit is in compliance with the laws, regulations, and orders described at 40 CFR § 144.4, including the National Historic Preservation Act (NHPA) and the Endangered Species Act (ESA) before a final Permit decision is made.

National Historic Preservation Act (NHPA)

Section 106 of the National Historic Preservation Act, 54 U.S.C. § 306108, requires federal agencies to consider the effects on historic properties of actions they authorize, fund or carry out. The EPA has determined that a decision to issue a Class V injection well permit for authorization of injection into the INJ#1 well constitutes an undertaking subject to the National Historic Preservation Act and its implementing regulations at 36 CFR part 800.

The Colorado State Historic Preservation Officer concurred on 30 November 2022, that the project area is not eligible for the National Register of Historic Places. Based on the documentation provided, EPA agrees that the finding of no historic properties affected [36 CFR 800.4(d)(1)] is appropriate for the subject undertaking.

Endangered Species Act (ESA)

Section 7(a)(2) of the Endangered Species Act (ESA), 16 U.S.C. § 1536 (a)(2), requires federal agencies to ensure that actions they authorize, fund, or carry out are not likely to jeopardize the continued existence of federally listed endangered or threatened species or result in the destruction or adverse modification of designated critical habitat of such species. The EPA has determined that a decision to issue a Class V permit for authorization of injection into the INJ#1 well would constitute an action that is subject to the Endangered Species Act and its implementing regulations (50 CFR part 402). Accordingly, the EPA will comply with these regulations by determining what, if any, effects this action will have on any federally listed endangered or threatened species or their designated critical habitat and by following any required ESA procedures. The EPA’s determination will be documented as part of the administrative record supporting the final Class V decision.

Executive Order 12898

On February 11, 1994, the President issued Executive Order 12898, entitled “Federal Actions to Address Environmental Justice (EJ) in Minority Populations and Low-Income Populations.” Potential language for conclusion: the EPA has concluded that there may be potential EJ communities proximate to the Authorized Permit Area. The primary potential human health or environmental effects to these communities associated with injection well operations would be to local aquifers that are currently being used or may be used in the future as USDWs. The EPA’s UIC program authority under the Safe Drinking Water Act is designed to protect USDWs through the regulation of underground injection wells. The EPA has concluded that the specific conditions of UIC Permit CO52432-12407 will prevent contamination to USDWs, including USDWs which either are or will be used in the future by communities of EJ concern. These USDWs could include the aquifer within the proposed injection zone in which case injection would only commence after a Major Modification is approved by the Director in accordance with Attachment IV, 2, of the Permit. The UIC program will be conducting enhanced public outreach to EJ communities by publishing a public notice announcement in local newspapers and holding a public hearing, if requested, or if public interest in the proposed permit is high.

The EPA used EJScreen for the initial step in assessing conditions near the proposed injection well. EJScreen is the EPA's environmental justice mapping and screening tool that provides the EPA with a nationally consistent dataset and approach for combining environmental and demographic socioeconomic indicators.[6] The EPA uses EJScreen as a preliminary step for considering environmental justice and screen for areas that may be candidates for additional consideration, analysis or outreach.[7] The EPA generated an EJ Screen Community Report for an assessment area 17 miles from the injection well location. The population within this area is 672. The EPA selected a radius of 17 miles to maximize population size without intersecting the City of Craig, Colorado. Including the large population of Craig in the assessment area would skew demographic results from characterizing the rural area where the injection well is located. The EJScreen report indicated that the EJ Indexes and Supplemental Indexes are below the state 80th percentile. The Low Income and People of Color Socioeconomic Indicator values are below the State Average value. Typically, the EPA will conduct more in-depth analysis when an EJ Index and Supplemental Index is at or above the state 80th percentile or a Low Income or People of Color Socioeconomic Indicator value is above the State Average value. In this case, the EPA determined that no additional EJ analysis is warranted based on screening levels.

[6] EPA, *What is EJScreen?* webpage, https://www.epa.gov/ejscreen/what-ejscreen. Accessed December 15, 2023.
[7] EPA, *How Does EPA Use EJScreen?* webpage. https://www.epa.gov/ejscreen/how-does-epa-use-ejscreen.

Attachment

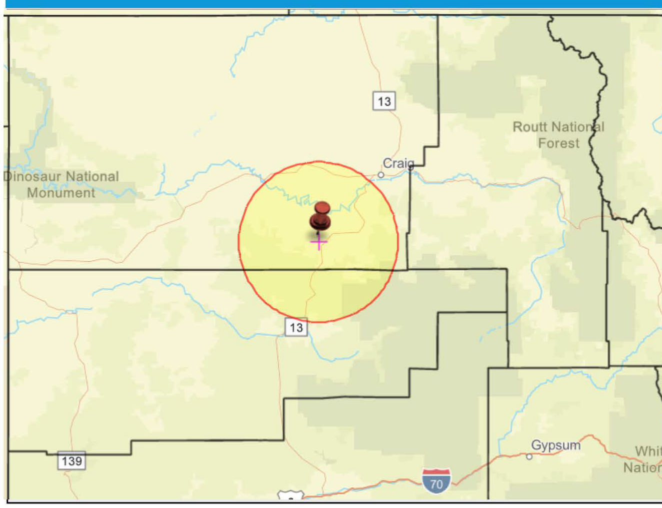
EJScreen Report

EPA

EJScreen Community Report

This report provides environmental and socioeconomic information for user-defined areas, and combines that data into environmental justice and supplemental indexes.

Area within a 17-mile radius of ColoWyo Class V Well



Low income: XX percent	People of color: XX percent	Less than high school education: XX percent	Limited English households: XX percent
Unemployment: XX percent	Persons with disabilities: XX percent	Male: XX percent	Female: XX percent
XX Average life expectancy	XX Per capita income	Number of households: XX	Owner occupied: XX percent

LANGUAGES SPOKEN AT HOME

LANGUAGE	PERCENT
English	XX%
Spanish	XX%
French, Haitian, or Cajun	XX%
German or other West Germanic	XX%
Russian, Polish, or Other Slavic	XX%
Other Indo-European	XX%
Korean	XX%
Chinese (including Mandarin, Cantonese)	XX%
Vietnamese	XX%
Tagalog (including Filipino)	XX%
Other Asian and Pacific Island	XX%
Arabic	XX%
Other and Unspecified	XX%
Total Non-English	XX%

BREAKDOWN BY RACE

White: XX%	Black: XX%	American Indian: XX%	Asian: XX%
Hawaiian/Pacific Islander: XX%	Other race: XX%	Two or more races: XX%	Hispanic: XX%

BREAKDOWN BY AGE

From Ages 1 to 4	XX%
From Ages 1 to 18	XX%
From Ages 18 and up	XX%
From Ages 65 and up	XX%

LIMITED ENGLISH SPEAKING BREAKDOWN

Speak Spanish	XX%
Speak Other Indo-European Languages	XX%
Speak Asian-Pacific Island Languages	XX%
Speak Other Languages	XX%

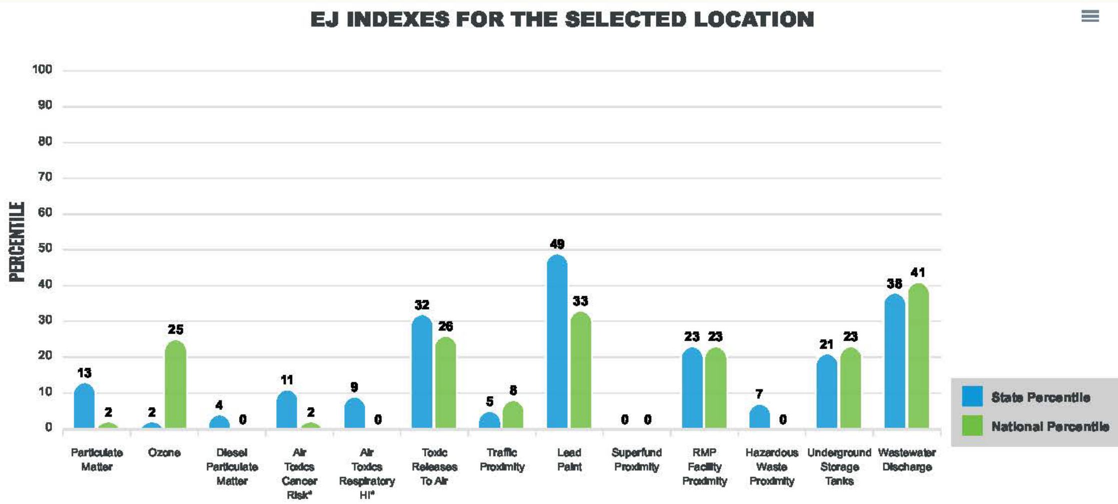
Notes: Numbers may not sum to totals due to rounding. Hispanic population can be of any race. Source: U.S. Census Bureau, American Community Survey (ACS) 2017 -2021. Life expectancy data comes from the Centers for Disease Control.

Environmental Justice & Supplemental Indexes

The environmental justice and supplemental indexes are a combination of environmental and socioeconomic information. There are thirteen EJ indexes and supplemental indexes in EJScreen reflecting the 13 environmental indicators. The indexes for a selected area are compared to those for all other locations in the state or nation. For more information and calculation details on the EJ and supplemental indexes, please visit the EJScreen website.

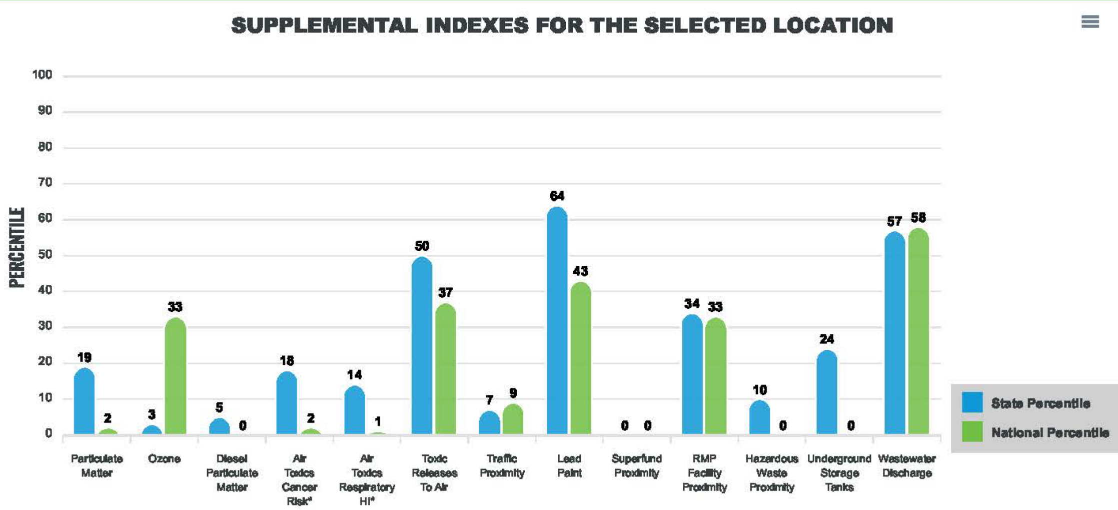
EJ INDEXES

The EJ indexes help users screen for potential EJ concerns. To do this, the EJ index combines data on low income and people of color populations with a single environmental indicator.



SUPPLEMENTAL INDEXES

The supplemental indexes offer a different perspective on community-level vulnerability. They combine data on percent low-income, percent linguistically isolated, percent less than high school education, percent unemployed, and low life expectancy with a single environmental indicator.



These percentiles provide perspective on how the selected block group or buffer area compares to the entire state or nation.

Report for XX

EJScreen Environmental and Socioeconomic Indicators Data

SELECTED VARIABLES	VALUE	STATE AVERAGE	PERCENTILE IN STATE	USA AVERAGE	PERCENTILE IN USA
POLLUTION AND SOURCES					
Particulate Matter ($\mu g/m^3$)	4.46	6.45	14	8.08	1
Ozone (ppb)	58.8	64.9	2	61.6	30
Diesel Particulate Matter ($\mu g/m^3$)	0.0158	0.268	4	0.261	0
Air Toxics Cancer Risk* (lifetime risk per million)	10	21	4	25	1
Air Toxics Respiratory HI*	0.097	0.25	3	0.31	0
Toxic Releases to Air	360	3,400	39	4,600	41
Traffic Proximity (daily traffic count/distance to road)	2.8	180	5	210	8
Lead Paint (% Pre-1960 Housing)	0.19	0.2	65	0.3	46
Superfund Proximity (site count/km distance)	0.0067	0.1	0	0.13	1
RMP Facility Proximity (facility count/km distance)	0.095	0.35	22	0.43	27
Hazardous Waste Proximity (facility count/km distance)	0.012	0.58	7	1.9	0
Underground Storage Tanks (count/km^2)	0.008	2.7	21	3.9	0
Wastewater Discharge (toxicity-weighted concentration/m distance)	0.018	710	59	22	72
SOCIOECONOMIC INDICATORS					
Demographic Index	16%	28%	27	35%	22
Supplemental Demographic Index	12%	11%	60	14%	44
People of Color	6%	32%	7	39%	15
Low Income	25%	25%	58	31%	46
Unemployment Rate	6%	5%	70	6%	64
Limited English Speaking Households	0%	2%	0	5%	0
Less Than High School Education	8%	8%	65	12%	49
Under Age 5	4%	5%	43	6%	40
Over Age 64	20%	16%	71	17%	66
Low Life Expectancy	19%	18%	63	20%	50

*Diesel particulate matter, air toxics cancer risk, and air toxics respiratory hazard index are from the EPA's Air Toxics Data Update, which is the Agency's ongoing, comprehensive evaluation of air toxics in the United States. This effort aims to prioritize air toxics, emission sources, and locations of interest for further study. It is important to remember that the air toxics data presented here provide broad estimates of health risks over geographic areas of the country, not definitive risks to specific individuals or locations. Cancer risks and hazard indices from the Air Toxics Data Update are reported to one significant figure and any additional significant figures here are due to rounding. More information on the Air Toxics Data Update can be found at: https://www.epa.gov/haps/air-toxics-data-update.

Sites reporting to EPA within defined area:

Superfund	0
Hazardous Waste, Treatment, Storage, and Disposal Facilities	0
Water Dischargers	45
Air Pollution	45
Brownfields	0
Toxic Release Inventory	3

Other community features within defined area:

Schools	0
Hospitals	0
Places of Worship	0

Other environmental data:

Air Non-attainment	No
Impaired Waters	Yes

Selected location contains American Indian Reservation Lands*	No
Selected location contains a "Justice40 (CEJST)" disadvantaged community	Yes
Selected location contains an EPA IRA disadvantaged community	Yes

Report for XX

EJScreen Environmental and Socioeconomic Indicators Data

HEALTH INDICATORS					
INDICATOR	HEALTH VALUE	STATE AVERAGE	STATE PERCENTILE	US AVERAGE	US PERCENTILE
Low Life Expectancy	19%	18%	63	20%	50
Heart Disease	6.6	4.8	88	6.1	62
Asthma	10.5	9.9	75	10	66
Cancer	6.8	5.9	70	6.1	62
Persons with Disabilities	13.7%	11.4%	72	13.4%	57

CLIMATE INDICATORS					
INDICATOR	HEALTH VALUE	STATE AVERAGE	STATE PERCENTILE	US AVERAGE	US PERCENTILE
Flood Risk	12%	5%	87	12%	73
Wildfire Risk	82%	33%	73	14%	89

CRITICAL SERVICE GAPS					
INDICATOR	HEALTH VALUE	STATE AVERAGE	STATE PERCENTILE	US AVERAGE	US PERCENTILE
Broadband Internet	12%	10%	68	14%	53
Lack of Health Insurance	11%	8%	77	9%	73
Housing Burden	No	N/A	N/A	N/A	N/A
Transportation Access	Yes	N/A	N/A	N/A	N/A
Food Desert	Yes	N/A	N/A	N/A	N/A

Footnotes

Report for XX