STATEMENT OF BASIS

SHELL FRONTIER OIL & GAS INC.
CLASS III SOLUTION MINING
RIO BLANCO COUNTY, CO

EPA AREA PERMIT NO. CO32210-00000

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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 the 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. EPA UIC permit conditions are based upon the authorities set forth in regulatory provisions at 40 CFR Parts 144 and 146, and address potential impacts to underground sources of drinking water. Under 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 of invasion of other private rights, or any infringement of other Federal, State or local laws or regulations. Under 40 CFR §144 Subpart D, 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.

Upon the Effective Date when issued, the Permit authorizes the construction and operation of injection wells so that the injection does not endanger underground sources of drinking water, governed by the conditions specified in the Permit. The Permit is issued for the operating life of the injection well or project unless terminated for reasonable cause under 40 CFR §144.39, §144.40 and §144.41. The permit is subject to EPA review at least once every five (5) years to determine if action is required under 40 CFR §144.36(a).

PART I. General Information and Description of Facility

Shell Frontier Oil & Gas Inc.
3737 Bellaire Blvd
Houston, TX 77025

on

May 12, 2011

submitted an application for an Underground Injection Control (UIC) Program area permit to construct and operate Class III injection well or wells within the permitted area which is described by:

Township 2S, Range 98W, Section 4, Lots 9, 10, 15, 16

The following injection well is included in this area permit:

Well Name	UIC Permit No.	Surface Location in Rio Blanco County, CO
H01	CO32210-09191	1820 FNL, 2050 FWL, SWNW S4, T2S, R98W

The application, including the required information and data necessary to issue a UIC Permit in accordance with 40 CFR Parts 144, 146 and 147, was reviewed and determined by EPA to be complete. Regulations specific to Colorado injection wells are found at 40 CFR §147 Subpart G.

The Permit will expire upon delegation of primary enforcement responsibility (primacy) for applicable portions of the UIC Program to the State of Colorado unless the delegated agency has the authority and chooses to adopt and enforce this Permit as a State Permit.

PROJECT DESCRIPTION

Shell Frontier Oil & Gas Inc. (Shell) has submitted an application for a Class III Solution Mining area permit to mine the Saline Zone in the Parachute Creek Member of the Green River Formation to initially include one injection well in their East Research, Development, and Demonstration (RDD) Project Site. Shell has received a 149 acre RDD lease from the Bureau of Land and Management (BLM) to demonstrate technologies capable of developing oil shale resources. In addition they also hold a Nahcolite Preference Right Sodium lease to commercially mine nahcolite.

There are two distinct phases in this project proposal. The first phase requires a Class III injection well, to deliver hot water into the targeted zone to leach the nahcolite for recovery at the surface. The nahcolite that will be recovered at the surface is expected to be a relatively small quantity that will be stored at the surface and appropriately disposed of, offsite. Once the formation has been leached, the zone will have increased permeability and the oil shale hydrocarbons can be more readily produced during the second phase. In the second phase, the formation will be heated to convert the kerogen (immature hydrocarbon in oil shale) to gases and liquids that will then be produced at the surface. The injection activity occurs only during the first phase where fluids are injected to recover nahcolite solution and is expected to take 6 months to 1 year. During the second phase, there will be no injection activity. The well will be converted to a monitoring well and will no longer be regulated under the UIC program. Shell estimates the second phase to take 1.5 to 2 years.

Well Field Configuration

Shell has defined the boundary of the project area (Figure 1), which also shows the area of review and placement of their wells in the pilot area. To allow for wells to be easily accessible for workovers and yet maintain the hexagonal geometry necessary to optimize heating for oil shale recovery, Shell will achieve both these objectives by utilizing deviated wells. Figure 2 shows the placement of the wells at the surface as well as their corresponding positions in the subsurface. The proposed H01 well will be located in the center of the hexagon (subsurface location) to leach the nahcolite. It is expected for the dissolution to progress most rapidly in the rich disseminated nahcolite zones of the T1 bed, Greeno bed, and other unnamed rich disseminated nahcolite units. In these most readily leachable beds, an approximately 20 feet radius circular region around the H01 well is expected to develop. Along the rest of the 153 feet vertical column, the horizontal extent of leaching will vary depending upon the leachability of the zone, but to a lesser extent than the rich disseminated nahcolite zones. In the event that the dissolution does not occur uniformly in a radial manner outward from the H01, Shell will request the addition of OB01 and/or OB03 wells to the area permit to initiate leaching through these wells. These wells will initially be used as observation or monitoring wells and when needed can be converted to an injection well to redirect the leach front to achieve a more symmetrical lateral leach pattern. A conversion plan is included in the permit in anticipation of these additional wells.

After the nahcolite leaching phase is completed, the H01 will be converted to a heater well, and if used for leaching, the OB01 and OB03 will be converted back to observation wells.

Well Operation

Initially, fresh potable water at ambient surface air temperature will be injected to establish circulation within the injection zone. Once circulation has been established, the injection water will be gradually heated to a maximum of 400 deg F at the surface. However, the designed surface operational temperature is 350 deg F. The heated fluid will be circulated so that the targeted temperature in the injection zone of 300 deg F is achieved. When the fluids have neared saturation, the recovery of the pregnant solution will begin. The concentration of the recovered fluid will be maintained at a high level, yet preclude the cooling-induced precipitation of the nahcolite as the fluid moves up the production tubing for recovery. The most efficient dissolution of nahcolite occurs when the solution is below the saturation limit for the salt. The targeted sodium bicarbonate concentration of the injection water is 3-4 weight% $NaHCO_3$. Therefore, part of the produced brine (pregnant solution) will be combined with fresh, heated make-up water for reinjection. No additional additives will be part of the injection stream.

The proposed injection zone is into the R3, L2, and R2 stratigraphic units in the Parachute Creek member of the Green River formation. A USDW is defined by its water quality (less than 10,000 mg/L total dissolved solids (TDS)) and ability to supply a public drinking water system (at least 1 gal/min, James R. Elder EPA memo, 1993). The proposed injection zone for the East RDD Project is within the regional Saline Zone, which is a saline-mineral cemented zone of mixed oil shale, marlstone, and nahcolite. The Saline Zone is dry (i.e. water will not flow from pores within the saline zone.) Shell has provided several lines of evidence to show that the saline zone is dry. These include knowledge of the geology and mineralogy, geophysical logs, conditions at the Horse Draw Mine, which is approximately 5 miles northeast of the project area.

Saline minerals fill the pore spaces between mineral grains in the saline zone to such an extent that porosity is occluded and permeability is too low to admit groundwater. Regionally, the saline minerals include nahcolite and dawsonite, with significant halite only in the upper part of the Saline Zone. In the East RDD area, the most abundant saline mineral is nahcolite. Because nahcolite is readily soluble, the saline zone must be inferred to be dry, lest the nahcolite minerals would have been dissolved away by groundwater. Geophysical logs, principally gamma ray/density logs, also show that porosity and permeability are extremely low in the saline zone. Permeability is less than 0.1 millidarcys in more than 95 percent of the saline zone in the OB04(SAW) well, and less than 1 millidarcy in the remainder. The Saline Zone contains layers of nahcolite of various morphologies that alternate with kerogen-rich layers and are remarkably continuous across the basin. Nahcolite morphologies that appear in the Horse Draw mine occur in the same sequences at the East RDD. Thus, it is inferred that the physical conditions at Horse Draw mine persist wherever the saline zone exists, and since the Horse Draw mine is dry, it is inferred that the Saline Zone is dry at the East RDD. During mining in the 1970s and 80s, operations were conducted on 4 separate working levels in the saline zone, all of which remained dry during mining. More recently, in 2009, Shell investigated the conditions inside the Horse Draw Mine Shaft and found that the mine remained dry after more than 25 years since the mine shaft was sealed at the surface.

PART II. Permit Considerations (40 CFR §146.34)

Geologic Setting

The Piceance Creek Basin located in northwestern Colorado is an elongated structural and stratigraphic depression, trending northwest - southeast. The basin is bounded by the Uinta Uplift to the north, White River Uplift to the east, Sawatch Uplift to the southeast, and the Douglas Creek Arch to the west. The Basin encompasses approximately 890 square miles, is asymmetric, and is structurally deepest in the northwest where crystalline basement rocks are estimated to be 24,000 feet below ground surface. The basin contains reserves of coal, natural gas, oil shale, and is also mined for the sodium mineral nahcolite.

In the area of Shell's East RDD Project Site, the Piceance Creek Basin is dominated by Uinta Formation outcrops that overlie the Green River Formation, both of Eocene age. The Uinta Formation is characterized by fine to medium grained sandstone interbedded with siltstone, sandy siltstone, marly siltstone, and thin beds of coarse grained or pebbly sandstone. The underlying Green River Formation is locally divided into three members; the Douglas Creek Member at the base, Garden Gulch Member above, and Parachute Creek Member at the top. (Locally at the Shell East RDD site, the Douglas Creek Member has not been identified.)

The Parachute Creek Member is the thickest and most economically important unit in the Green River Formation. The Parachute Creek Member has a large areal extent and contains all of the commercial resources of oil shale and nahcolite. Oil shale, which is kerogen-bearing marlstone, and dolomite marlstone, are the dominant lithologies of the Parachute Creek Member. Nahcolite beds and segregates are present in the Saline Zone, which occupies the lower part of the Parachute Creek Formation in basin center. Notable concentrations of dawsonite occur within the Saline Zone, and halite occurs sporadically in the upper Saline Zone and principally at the basin deposition center (i.e., not at the East RDD project).

The Saline Zone constitutes the most important resource interval in the entire Piceance Creek Basin. It not only contains tremendous quantities of oil shale but mineable concentrations of nahcolite and significant concentrations of dawsonite, and halite in basin center where the upper contact of the Saline Zone is overlain by the hydrostratigraphic L4 WBI. Recent resource assessments by the U.S. Geological Survey indicate that the Saline Zone in the Piceance Creek Basin represents an in-place oil shale resource of about 1.9 million barrels per acre and nahcolite resources on the order of 4.5 billion tons, or 542,541 tons per acre. The U.S. Department of Interior indicated that dawsonite resources in the Saline Zone comprise approximately 195,000 tons per acre.

The Saline Zone is bounded at the top by the Dissolution Surface, and at the base by a horizon that marks the lowermost occurrence of nahcolite in the R2 zone. Besides parts of the L4 and L0 zones, the Saline Zone at the East RDD lease area also includes all of the R4, L3, R3, L2, R2, L1, R1, and L0 stratigraphic zones.

Below the Parachute Creek Member is the Garden Gulch Member, where the oil shale is characterized as clay rich, roughly 60% clay and 40% carbonate, in contrast to the carbonate-rich Parachute Creek oil shale, which is roughly 60% carbonate and 40% clay. The oil shale interval within the Parachute Creek and Garden Gulch Members is further subdivided lithologically into seventeen alternating rich (R) and lean (L) oil shale stratigraphic zones. Shell has targeted a zone in the R4 Seal within the Parachute Creek Member for shale oil recovery.

The Garden Gulch Member underlies the Parachute Creek Member and is more than 100 feet thick in the RDD Lease area. Like the overlying Parachute Creek Member, the Garden Gulch Member can be subdivided into rich and lean oil shale zones. The uppermost zone is designated the L1 zone, and the contact between the L1 and the overlying R2 is called the "Blue Marker." The L1 zone is composed of clay-rich lean oil shale and claystone and is about 17 feet thick. The L1 zone is underlain by the R1 zone, which is about 130 feet thick and composed of clay-rich oil shale. Below the R1 zone is the L0 zone. It ranges in thickness from 20 to 30 feet and has low-grade oil shale. The L0 zone has a distinct influence on geophysical logs (density and resistivity). Early workers referred to this geophysical "kick" as the "Orange Marker." Below the L0 zone is the lowermost continuous interval of oil shale in the Green River Formation, the R0 zone. It is similar to the R1 zone and is composed of clay-rich oil shale and in one drill core it was found to be about 127 feet thick. Below the R0 zone additional thin beds of clay-rich oil shale are present, though they are interbedded with considerable quantities of sandstone, siltstone and lacustrine shale.

Hydrogeologic Setting

The primary water-bearing zones that exist in this area are within the Uinta, Green River and Wasatch Formations. The first encountered groundwater in the RDD Project Site is approximately 300 feet below ground surface in the Uinta Formation. The general groundwater flow pattern is from the outer perimeter of the basin, where most recharge occurs, toward the center of the basin where there is discharge to the perennial streams, more active evapotranspiration, and a greater frequency of springs.

The Uinta Formation extends downward generally from ground surface and is moderately transmissive due to its relatively low permeability. At the basin scale, the Uinta is conceptualized as an unconfined aquifer, with stratigraphic heterogeneity that imparts varying degrees of confinement to the deeper strata. "Tongues" of low permeability, kerogen-bearing strata exist in the lower portion of the Uinta and these provide confinement to underlying stratigraphic units.

Historically, the Green River Formation has been conceptualized as a sequence of relatively transmissive lean zones (i.e., less kerogen), which are each confined by overlying and underlying rich zones (i.e., more kerogen) having very low permeability. Within the Parachute Creek Member of the Green River, the Dissolution Surface is a post-depositional subsurface dissolution feature and represents the lowermost penetration of circulating groundwater into the Parachute Creek Member. Above the Dissolution Surface, nahcolite and halite have been largely dissolved away by migrating groundwater, leaving an array of collapse breccias, nodular leach cavities, and otherwise permeable rock wherein pore spaces have derived by the dissolution of nahcolite and halite.

Nearly all groundwater in the Green River formation flows through the secondary porosity fractures and dissolution/collapse features as the fine-grained porous matrix is nearly impermeable. The lean zones tend to be more brittle, contain a higher degree of fracturing, and are thus much more permeable than the rich zones.

Shell has conducted extensive hydraulic testing in the Piceance Basin to refine the intervals of fracture and flow resulting in hydrostratigraphic zones that differ from the historical definition of stratigraphic zones whereby the water-bearing intervals (WBI) were considered to be equivalent to stratigraphic subdivisions. Based on this differentiation of hydrostratigraphic units from stratigraphic units, the WBIs are generally seen to be thicker than the stratigraphic units of the same names. In particular, the L4 WBI is much thicker than the L4 defined solely on the basis of geologic stratigraphy. For purposes of this Permit, the following geologic setting and definition of geologic units pertinent to the UIC permit, the hydrostratigraphic definition of each WBI will be described for strata from the surface to the Dissolution Surface. The balance of the stratigraphic section below the L4 (including the R4, L3, R3, L2, R2, L1, and R1) will be referred to as the "R4 Seal" because this part of the stratigraphic section corresponds to the impermeable Saline Zone (Figure 3). Table 2.1 provides a description of the hydrostratigraphy of the East RDD.

Uinta Hydrostratigraphic Zone

The Uinta Formation consists of discontinuous layers of silty sandstone, siltstone, marlstone and lenses (or tongues) of kerogen-bearing marlstone. It forms the surficial bedrock over most of the northern Piceance Basin. At the East RDD, the hydrostratigraphic sequence of the Uinta consists of a 260 foot thick, low permeability zone overlying a 684 foot thick water-bearing interval.

R8 Hydrostratigraphic Zone

The R8 oil shale zone (a hydrostratigraphic "seal" in Shell terminology) is the next hydrostratigraphic unit and is approximately 60 feet thick within the East RDD. It is composed of interbedded oil shales and occasional interbeds of siltstone, marlstone and volcanic tuff. Oil shale and marlstone are typically laminated and tan to dark brown in color.

A-Groove (L7) Hydrostratigraphic Zone

Within the East RDD, the A-Groove or L7 hydrostratigraphic unit/WBI is approximately 114 feet thick. It is composed of tan to yellowish-tan lean oil shale and silty marlstone, and has a distinct "weathered" appearance

R7 (Mahogany Zone) Hydrostratigraphic Zone

The R7 hydrostratigraphic unit/seal is approximately 62 feet thick at the East RDD. The kerogen-rich oil shale unit is usually laminated or structureless; however, blebby oil shale is present, especially in the richest beds.

B-Groove (L6 Hydrostratigraphic Zone)

Similar to the A-Groove, the B-Groove or L6 hydrostratigraphic unit (WBI) is composed of marlstone, silty marlstone and lean to low-grade oil shale. Most of the B-Groove has a weathered or leached appearance and the upper one-half often contains a thick (5 to 10 feet) rubble horizon. The approximate thickness of the B-Groove at the East RDD is 161 feet.

R6 Zone Hydrostratigraphic Zone

The R6 hydrostratigraphic zone/seal is approximately 40 feet thick at the East RDD. The unit is composed primarily of oil shale, vuggy oil shale, and marlstone. Dissolution features are minor and rare in the R6 zone at the East RDD site.

L5 Zone Hydrostratigraphic Zone

The L5 hydrostratigraphic zone/WBI is similar lithologically to the overlying R6 zone, however, it has a lower average oil shale content and is therefore more brittle and contains more fractures. Throughout the East RDD, the L5 zone is above the saline zone and is about 142 feet thick. Stratification in these rocks is generally laminated, sometimes structureless.

R5 Zone Hydrostratigraphic Zone

The R5 seal is an important hydrostratigraphic zone/seal in the Parachute Creek Member and has been regionally tested to have very low permeability. At the East RDD, the R5 is approximately 40 feet thick.

L4 Zone Hydrostratigraphic Zone

The L4 hydrostratigraphic zone/WBI is a nahcolite poor marlstone with thin interbeds of kerogen-bearing rock. Permeability derives primarily from vugs formed by dissolution of nahcolite. It is approximately 450 feet thick at the East RDD.

Dissolution Surface

The so-called Dissolution Surface separates the currently present and historically present sodium mineral-bearing (nahcolite, dawsonite, and halite) Parachute Creek Member into two major units, the Saline Zone and the overlying Leached Zone. The Dissolution Surface occurs at a depth of 2,013 feet divides the L4 and R4 hydrostratigraphic zones at the East RDD Project Site.

The Dissolution Surface also marks the interface above which free ground water exists and below which no free ground water occurs due to the presence of unleached saline minerals. The Leached Zone is the result of dissolution of soluble saline minerals by downward percolation of ground water. The Saline Zone is a complex array of bedded and non-bedded nahcolite with local occurrences of bedded halite deposits.

R4 Seal Zone

The R4 seal zone spans the stratigraphic interval from the base of the Dissolution Surface to the top of the Wasatch Formation. The dominant feature of the seal is the presence of nahcolite that occupies the available porosity. The target interval for activities related to the East RDD is within the R4 seal as defined.

TABLE 2.1
GEOLOGIC SETTING

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Hydrostratigraphic Unit	Top (ft)*	Base (ft)*	TDS (mg/l)	Lithology
Uinta	0	944	710 - 1,000	sandstone/siltstone
Green River - R8	944	1,004		oil shale
Green River - A Groove	1,004	1,118	830 - 850	marlstone
Green River - R7	1,118	1,180		oil shale
Green River - B Groove	1,180	1,341	710 - 770	marlstone
Green River - R6	1,341	1,381		oil shale
Green River - L5	1,381	1,523	700 - 710	marlstone
Green River - R5	1,523	1,563		oil shale
Green River - L4	1,563	2013	45,000	marlstone
Green River - R4 Seal	2013	2,654[1]		nahcolite cemented oil shale and marlstone
Top of Wasatch	2,654[1]			marly shale

*estimated top and base of formations are estimated from the OB04(SAW) well except where noted
[1]estimated base of formation estimated from nearby projects

Proposed 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 is listed in TABLE 2.2.

Injection will occur into an injection zone that is separated from USDWs by confining zone(s) which is free of known open faults or fractures within the Area of Review.

The proposed injection zone is within the R4 Seal hydrostratigraphic unit from 2,100 to 2,300 feet, rounded depths of the open interval. The Dissolution Surface (approximately located at 2,013 feet) marks the extent of groundwater infiltration and top of the saline mineral deposits, or Saline Zone. The proposed injection zone is located below the Dissolution Surface, within the Saline Zone, where groundwater is not present, remains dry, and the units are not considered USDWs. In general the injection zone is comprised of very tight, very low permeability nahcolitic oil shale.

TABLE 2.2
INJECTION ZONE

Hydrostratigraphic Unit	Top (ft)*	Base (ft)*	TDS (mg/l)	Fracture Gradient (psi/ft)
Green River - R4 Seal	2,100	2,300	NA	0.68

*injection zone top and base correspond to the open hole where the dissolution will occur, plus an additional

The proposed injection zone is a complex array of bedded and non-bedded nahcolite. The nahcolite occurs as finely disseminated crystals, nodules, crystalline aggregates, and several thin continuous beds. The dominant continuous beds within the injection zone are the “upper” and “lower” Greeno and TI beds, with a greatest thickness of approximately twelve feet. On a layer by layer basis, the grade of nahcolite in the injection zone ranges from less than 1% to about 80%, and the average grade is 26 weight%. Approximately 1000 tons of nahcolite is expected to be leached resulting in a maximum 20 feet leaching radius, mainly in these continuous beds.

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 confining zone or zones are listed in TABLE 2.3.

Hydrostratigraphic rich zone R5 appears to operate regionally as a highly confining unit and this is reflected in the tendency for a large hydraulic head difference between water-bearing intervals (WBIs) or aquifers above and below the R5 in the region that is northwest of the RDD.

The United States Geological Survey (USGS) Produced Water Database was reviewed for regional water quality data below the injection zone. Based on the TDS values contained in the database, the Wasatch and Mesa Verde may be USDWs, near the East RDD Project Site. A lower confining layer has also been identified below the injection zone.

TABLE 2.3
CONFINING ZONES

Hydrostratigraphic Unit	Top (ft)*	Base (ft)*	Formation Lithology
upper confining units			
Green River - R8	944	1,004	oil shale

Green River - R7	1,118	1,180	oil shale
Green River - R6	1,341	1,381	oil shale
Green River - R5	1,523	1,563	oil shale
Green River - R4 Seal	2,013	2,100	oil shale & saline minerals
lower confining unit			
Green River - R4 Seal	2,300	2,654[1]	oil shale & saline minerals

*estimated top and base of formations are estimated from the OB04(SAW) well except where noted
[1]estimated base of formation estimated from nearby projects

Underground Sources of Drinking Water (USDWs)
Aquifers or the portions thereof which contain less than 10,000 mg/l total dissolved solids (TDS) and are being or could in the future be used as a source of drinking water are considered to be USDWs. The known USDWs within the lease area are the Uinta Formation, the A-Groove, B-Groove, and upper portions of the Dissolution Surface in the L5 stratigraphic unit. The range of TDS values can be found in TABLE 2.4.

TABLE 2.4
UNDERGROUND SOURCES OF DRINKING WATER (USDWs)

Hydrostratigraphic Unit	Top (ft)*	Base (ft)*	TDS (mg/l)
Uinta	0	944	710 - 1,000
Green River - A Groove	1,004	1,118	830 - 850
Green River - B Groove	1,180	1,341	710 - 770
Green River - L5	1,381	1,523	700 - 710
Top of Wasatch	2,654[1]		

*estimated top and base of formations are estimated from the OB04(SAW) well except where noted
[1]estimated base of formation estimated from nearby projects

Based on the water quality data found in the USGS Produced Water Database, the Wasatch and Mesa Verde may also be USDWs near the East RDD Project, but site specific data is not available at this time. As mentioned above a lower confining layer has also been identified below the injection zone.

PART III. Well Construction (40 CFR §146.22)

The approved well completion and conversion plans, incorporated into the Permit as APPENDIX A, will be binding on the Permittee. Modification of the approved plan is allowed under 40 CFR §144.52(a)(1) provided approval is obtained from the Director prior to actual modification.

All well materials must be compatible with fluids with which the materials come into contact and capable of withstanding the full temperature range planned for this project. The maximum temperature of the fluids within the wellbore will be 400 deg F.

Casing and Cementing
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 fluids into USDWs. Well construction details for this injection well are shown in TABLE 3.1.

TABLE 3.1
WELL CONSTRUCTION REQUIREMENTS

Casing Type	Hole Size (in)	Casing Size (in)	Cased Interval (ft)	Cemented Interval (ft)
Surface	14.75	10.75	0 - 50	0 - 50
Longstring	9.875	7.63	0 - 2,122	0 - 2,122
Injection Tubing		2.375	NA	NA
Production Tubing		2.375	NA	NA

The longstring casing will be equipped with cement baskets to keep cement from falling back into the hole during cement displacement.

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

Area Of Review (AOR)
Under 40 CFR §146.6, the area permit AOR may be a fixed distance of not less than one quarter (1/4) mile outside of the UIC permit boundary or a circumscribing area in which the pressures in the injection zone may cause the migration of the injection and/or formation fluid into a USDW. For this area permit, the AOR is defined to be another quarter mile outside of the UIC permit boundary as shown in Figure 1.

This AOR is considered conservative since the experiment is a recirculating process where the fluids injected will also be taken up to surface and the increase in formation pressure is not the same as that of typical injection projects.

Within the AOR, there are no drinking water wells, but Shell has seven monitoring wells and a gas production well (Williams Company) also exist. An additional 19 wells will be installed prior to operations. Below is a summary of relevant information regarding the existing and proposed wells within the quarter mile AOR:

TABLE 4.1
AOR AND CORRECTIVE ACTION

EXISTING WELLS

Well Name	Well Type	Penetrate Confining?	Total Depth (ft)	TOC Depth (ft)	CAP Required (Y/N)
135-4-298-L4	Monitoring	Yes	2,000	0	N
138-4-298-L4	Monitoring	No	1,798	0	N
138-4-298-L5	Monitoring	No	1,542	0	N
138-4-298-L6	Monitoring	No	1,354	0	N
138-4-298-L7	Monitoring	No	1,134	0	N
138-4-298-UT	Monitoring	No	960	0	N
32-4-298	Oil and Gas	Yes	11,064	0	N
OB04 (SAW)	Monitoring	Yes	2,342	0	Y

PROPOSED WELLS

Well Name	Well Type	Penetrate Confining?	Total Depth (ft)	TOC Depth (ft)	CAP Required (Y/N)
H02 to H13 (12 wells)	Heater	Yes	2,285	0	TBD
P01 and P02 (2 wells)	Production	Yes	2,342	0	TBD
OB01 and OB03 (2 wells)	Monitoring/ Backup Injection Wells	Yes	2,285	0	TBD
OB02	Monitoring	Yes	2,342	0	TBD
OB05 and OB06 (2 wells)	Monitoring	Yes	2,285	0	TBD

The closest mapped fault is the Dudley Bluffs Graben, which is a major structural feature adjacent to the Piceance Creek Dome and in the vicinity of Piceance Creek and Ryan Gulch, that is a west-north westerly trending structure that terminates approximately three (3) miles east of the East RDD Project. An approximately 1 mile long northerly to northwesterly trending depression (with 20 to 25 feet of vertical displacement and approximately 1/8 mile wide) occurs in the vicinity of the East RDD permit boundary, east and outside of the projected activities. This structure appears to be a primary depression on the lake floor that subsequently was loaded with chemical precipitates – primarily nahcolite and muds with dolomitic composition.

Shell has identified all wells within the area permit AOR and there are no drinking water wells or residences. Shell brings in drinking water as needed.

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.

The OB04 (SAW) well is improperly constructed showing poor cement through the confining zone. Appendix F details the CAP and will be implemented prior to authorization to inject. There are also a number of wells that have not been constructed. After construction, documentation will be provided to EPA for evaluation to make a final determination on whether or not CAP will be required for these proposed wells.

PART V. Well Operation Requirements (40 CFR §146.23)

Approved Injection Fluid

Approved injected fluids are limited to:
1. fresh water (no additives) and reinjection of concentrated brine from the dissolved nahcolite within the injection zone
2. inert gas placed in the annulus of the injection and production tubings and longstring casing

Shell has proposed injection of an inert gas such as nitrogen that will extend from surface (through the annulus of the tubings and longstring casing) into the leaching interval to control the top elevation of the brine solution. The variable pressurized gas cap will be used to insulate the formation from the injection fluid and help control the upward growth of leaching interval and focus solution mining to specific horizons.

Injection of any hazardous waste as identified by EPA under 40 CFR §261.3 is expressly prohibited.

Injection Pressure Limitation
Injection pressure, measured at the wellhead, will not exceed the maximum calculated to assure that

the pressure used during injection does not initiate new fractures or propagate existing fractures in the injection zones. In no case shall injection initiate fractures in the confining zone or cause the migration of injection or formation fluids into a USDW.

Shell has performed a Step Pressure Test and a Microfrac Test on the OB04 (SAW) to provide information on the formation fracture pressure. During the Step Pressure Test, the pressure was incrementally increased and then shut in for one hour to allow pressure to fall off. The pressure fall-offs have the same behavior (decay rate with time) indicating that the formation did not break down in any of the pressure test steps. The highest pressure achieved was 700 psi corresponding to a bottom hole pressure (BHP) of 1,787 psi at 2,220 or 0.805 psi/ft gradient.

During the Microfrac test, the breakdown occurred at BHP 2,096 psi, measured at 2,220 feet which corresponds to a gradient of 0.94 psi/ft. In the microfrac test, the fracture pressure was also monitored as fracture closed, it was then reopened and closed twice more. A conservative fracture gradient value will be used to determine the maximum allowable injection pressure (MAIP), 0.68 psi/ft, the smallest value from the test results below.

Stage	Step	BHP @ 2,220' (psi)	Fracture Gradient (psi/ft)*
1	Breakdown	2,096	0.94
	Closure	1,520	0.68
2	Reopening	1,620	0.73
	Closure	1,540	0.69
3	Reopening	1,540	0.69
	Closure	1,580	0.71

*calculated as BHP/2,220' (measured pressure depth)

The formation fracture pressure can be determined according to the following formula:

$$FP = [fg - (0.433 * sg)] * d$$

FP = formation fracture pressure (measured at surface)
fg = fracture gradient (from submitted data or tests)
sg = specific gravity (of injected fluid)
d = depth to top of injection zone (or top perforation)

Shell estimates that at the operating concentration of 15 wt% and 300 degrees Fahrenheit, the produced brine has a specific gravity of 1.16. At a depth of 2,090 feet (top of the injection zone) and using the fracture gradient (0.68 psi/ft), the fracture pressure is approximately 370 psig.

Shell is also authorized to inject an inert gas into the annulus between the casing and tubing strings. To be able to effectively displace the fluids in the well and counterbalance the hydrostatic pressures exerted by the barren liquor at 370 psig, at the greatest depth, an annular pressure of 1510 psig is required. The Gas Cap MAIP is set at 1,510 psig.

Shell has proposed to use a nitrogen gas blanket to maintain positive pressure on the leach solution and thereby induce movement of the brine solution back up the production tubing, and to help control upward leaching of the solution into overlying layers.

Injection Volume Limitation
Cumulative injected fluid volume limits are set to assure that injected fluids remain within the boundary of the exempted area. Cumulative injected fluid volume is limited when injection occurs into an aquifer that has been exempted from protection as a USDW.

Presently, there are no aquifer exemptions associated with this permit and no fluid volume limits. Furthermore, in this process, as fluids are injected into the subsurface, the fluids are recirculated and brought back up to the surface within the same well.

Mechanical Integrity (40 CFR §146.8)
An injection well has mechanical integrity if:

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

The Permit prohibits injection into a well which lacks mechanical integrity. The Permit requires that the well demonstrate mechanical integrity prior to injection and periodically thereafter. A demonstration of mechanical integrity includes both internal (Part I) and external (Part II). The methods and frequency for demonstrating Part I and Part II mechanical integrity are dependent upon well-specific conditions as explained below.

Internal Mechanical Integrity (Part I MI) will be demonstrated prior to beginning injection. A successful Part I Mechanical Integrity Test (MIT) is required prior to receiving authorization to inject and repeated no less than five years after the last successful MIT. A demonstration of Part I MI is also required prior to resuming injection following any workover operation that affects the casing.

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. The pressure test requires removing both tubings and setting a temporary packer or retrievable bridge plug at the base of the longstring casing.

External Mechanical Integrity (Part II MI) will be demonstrated by conducting a Temperature Survey. A baseline Temperature Survey will be conducted prior to authorization to inject. The first demonstration following the baseline Temperature Survey will be made within the two years after injection has commenced. Subsequent demonstrations are required no less than five years after the last successful MIT.

PART VI. Monitoring, Recordkeeping and Reporting Requirements

The goals of the proposed monitoring programs are to ensure that the well integrity is not compromised as a result of RDD activities. Temperatures and pressures will be closely monitored to ensure certain established limits are not exceeded, and to monitor the water quality in the USDWs. The monitoring program is described below and the requirements are summarized in APPENDIX D of the Permit.

Once an alarm sounds or upon discovery that there is an exceedance in the permit condition, the response and shutdown process will be followed.

<u>Response and Shutdown Process</u>
The response and shutdown process entails investigating the origin to determine that the permit exceedance and/or alarm sounded as a result of a valid concern and not a false alarm before

proceeding to the shutdown process. The shutdown process entails immediately ceasing injection, to determine cause and remediate the problem. All events that trigger the shutdown process will be reported to the EPA within 24 hours. All events that sound an alarm due to a permit condition exceedance will be documented and reported in the quarterly report.

Injection Well Monitoring Program

Continuous monitoring will be carried out with instrumentation that will be capable of recording at least one value for each of the parameters (annulus pressure, injection and production densities, flowrates, volumes, pressures, and temperatures) at least every thirty (30) seconds. Recordings should be made at least once every ten (10) minutes.

Monthly averaged, maximum, and minimum values for annulus pressure, injection and production densities, flowrates, volumes, pressures, and temperatures are required to be reported as part of the Quarterly Report to the Director.

TUBING CASING ANNULUS MONITORING

The annulus between the injection and production tubings and longstring casing will be continuously monitored to ensure that the pressure of the gas blanket does not exceed the MAIP. Additionally, abnormal changes in pressure will be investigated to provide indication of problems with the casing or tubing integrity.

INJECTATE AND PRODUCTION FLUID SAMPLING

The Permittee will be required to provide access for sampling the injected fluid, via a tap, isolated by shut-off valves. All sampling and measurement taken for monitoring must be representative of the monitored activity.

Sodium bicarbonate equivalent assay will be derived from continuous gravimetric measurements of the injection fluid and produced fluid. Such equivalent assays from gravimetric measurements will be derived from periodic chemical analysis of the injection and recovery streams, and corrected for dissolved solids other than sodium bicarbonate. The information will be used to better understand leaching interval growth.

A weekly bicarbonate assay will be performed on the injected barren liquor as well as the produced fluid to provide chemistry information on the injectate and produced fluid. The Permittee must also analyze, quarterly, a sample of the injectate for the pH, TDS, specific gravity, and specific conductivity. This analysis will be reported to EPA as part of the Quarterly Report to the Director.

WELLHEAD MONITORING

The Permittee will be required to install and maintain wellhead equipment. Required wellhead equipment includes but is not limited to: 1) continuous recording devices for injection pressure, produced fluid and injectate temperatures, production and injection flow rates, and annular pressure, 2) shut-off valves located at the wellhead on the injection; 3) flow meters that measure the cumulative volumes of injected and produced fluids; 4) fittings, thermocouples, or transducers attached to the production tubing and the annulus between the longstring casing and tubings.

TEMPERATURE AND PRESSURE

The injectate temperature will be continuously monitored to ensure that the operating temperature does not exceed the permit limit of 400 deg F and does not adversely affect the formations containing USDWs. Fluid temperature in the formation will be provided by two dual thermocouples on the production tubing string, and will provide four discrete temperature readings between the depths of approximately 2,148 feet to 2,260 feet, corresponding to the main leaching targets. For the

H01 well only, temperature in the crown will also be monitored with a dual thermocouple attached to the outside of the longstring casing at depths of 1,990 feet and 2,060 feet. Additionally, two transducers will also be placed on one of the tubing strings to provide continuous temperature and pressure readings near the top and base of the targeted mine interval, at approximately 2,122 feet and 2,260 feet.

A number of kerogen pyrolysis experimental studies have been performed to determine the kinetic rates as a function of temperature. By weight, Green River Shale is approximately 10% shale oil. At temperatures below 500 deg F, only 10% of the shale oil is extractable, or 1% by weight of the formation. Those experiments, conducted in organic solvents, evolved higher amounts of kerogen than can be expected for actual conditions where heating takes place in groundwater. In general, the kinetic relationship between the temperature and the time is governed by Arrhenius' law, where, at higher temperatures, a shorter amount of time is required for the shale oil to be produced. At lower temperatures, the amount of time exponentially increases. Using the reaction constants from the Burnham, et al., 1987[1] paper, at 400 deg F, it would take over 1.7 years before the kerogen in the shale oil is generated. Therefore, at a maximum temperature of 400 deg F, and an injection duration of less than 1 year, oil is not expected to be generated during the project life. Shell is permitted to operate at a maximum temperature of 400 deg F, however, Shell intends to operate at their design surface temperature of 350 deg F to achieve a 300 deg F within the injection zone. Additionally, along the wellbore, insulation is provided by the N2 blanket, longstring steel casing, and cement behind the casing, to further minimize effects to the formation away from the injection zone. The permit duration is for the life of the project, however the leaching phase is 1 year or less, and the total duration of the experimental project that will include the leaching and pyrolysis phase is not expected to exceed ten years. In the event that the project exceeds the planned period of injection, the following table provides the number of days that injection is allowed at temperatures below 400 degF.

Temperature deg F	Number of Days	Number of Years
370	4,417	~12
371 - 380	2,276	~6.2
381 – 390	1,191	~3.3
391 – 400	633	~1.7

LEACHING INTERVAL MONITORING

During the injection phase of this project, Shell intends to in-situ solution mine nahcolite from the Saline Zone. The targeted interval is approximately 153 feet in height and will have an average radius of 20 feet. The geometry of the leached mass will be affected by the variable rates of nahcolite dissolution, which depends on nahcolite richness, morphology, and connectivity between nahcolite segregations. Nahcolite rich layers that are most susceptible to leaching will have larger leach radii than nahcolite poor, and leachable layers that come in contact with the leach solution will have the fastest and largest amount of lateral penetration.

Leaching interval development shall be monitored to estimate the extent to which the nahcolite has been produced. Because the leached solution interval will be a matrix of oil shale rather than a void, size and shape must be determined by indirect methods. Material balances of the volumetric fluid flow rates into and out of the leaching interval shall be performed. Continuous monitoring of flow rates and densities will provide an ongoing material balance, which will allow the Permittee to make calculations of the mass of nahcolite extracted, and this information will be submitted with the quarterly report.

[1] "*Comparison of Methods for Measuring Kerogen Pyrolysis Rates and Fitting Kinetic Parameters*" by Burnham et al. UCRL-95660 193rd Meeting of the American Chemical Society, Denver, Colo. (Apr. 5, 1987)

Additionally, the leaching interval will be closely monitored through the use of 6 monitoring/observation wells during the leaching phase, three wells found in the interior (unless converted to an injection well) of the heater well configuration and three wells exterior of the configuration. These wells are shown in Figure 2. The leach front will be monitored by changes in temperature and pressure, rock temperatures will increase ahead of the actual leaching front and at some leach distance the temperature sensors will detect an increase. In addition, once the leaching front breaks through to a well, pressure sensors will detect the increase in pressure as the leach well pressure will be higher than formation pressure.

SUBSIDENCE MONITORING

The subsidence monitoring plan will include subsurface monitoring to detect subsurface movement. Shell has elected not to provide for surface monitoring due to the width (20 feet radius) and depth of the project (> 2,100 feet). Furthermore, the subsidence monitoring that is required is intended to provide indication of subsurface movement well before surface movement is to occur.

Subsurface Subsidence

Shell is proposing to implement two subsidence monitoring technologies, time domain reflectometry (TDR) and radioactive markers. The TDR has an advantage over other subsidence monitoring methods in that the monitoring is a continuous process, whereas the radioactive markers are logged periodically. Other subsurface monitoring techniques may be employed, provided the operator submits sufficient information to demonstrate that the alternative will provide equivalent subsidence monitoring to that of the existing monitoring technique, and the alternative monitoring technique is approved by the Director. If approved, the Permit will be changed to include the new alternative by issuance of a Minor Modification.

<u>Time Domain Reflectometry (TDR)</u>

TDR is an electrical pulse-testing technique, whereby a pulse is created in the coaxial cable and returns a reflected signal when the cable experiences a crimp or elongation. The TDR will be installed in OB02 from the dissolution surface (2,013’) to within 70 feet of the injection zone (2,074 feet). OB02 is 9.24 feet from H01, the injection well. Materials will be used that can withstand the maximum anticipated temperature of the project.

<u>Radioactive Markers</u>

Radioactive pip tags will be located in to the casing on OB02 approximately every 20 feet from 1,800 feet to 2,124 feet and in OB04 approximately every 20 feet from 1,800 feet to 2,270 feet that are permanently cemented in the well. The tags consist of a weak gamma ray source such as Cobalt-60 or Zinc-65 which produces a radiation level of 0.014 mrem/hr at one foot from the source. Shell estimates, owing to the relatively short half-life of the radioactive marker (5.2 years for Co-60 and 240 days for Zn-65), the small size of the pip tag, their location in the casing collars, and their great depths (greater than 1,500 feet), and given that no water wells exist in the zone to be monitored, the risk of contact with environmental receptor is estimated to be small to none.

The OB04(SAW) well is outside of the leached region and OB02 is within. Shell states that movements as small as 0.02 inches can be measured accurately. If the formation subsides (or heaves) the casing cement will subside with it, and the casing will stretch due to the pressures. A baseline log will be required to establish the original depths of the radioactive markers and subsequent monitoring will occur on a quarterly basis. The log run will also provide a signature of the formation and can possibly detect more subtle changes to the formation that do not lead to casing stretches, by comparing location of casing collar locator relative to the formation.

Shell has performed a geomechanical assessment, modeling a 130 feet by 20 feet radius cylinder. The geomechanics model assumes that the entire leach volume is void and that the lower crown will be subjected to slight heating from the leach/heater zone. The modeling results indicate that under these circumstances, the potential overstressed zone in the overburden rock does not extend more than 10 feet into the crown, leaving more than 100 feet of stable rock above. Shell considers both assumptions to be conservative during the leaching phase. During this phase the oil shale and nahcolite structure that remains in place will provide formational support, reducing the risk of subsidence. Also, during the leaching phase, the pyrolysis heaters will not be used. During pyrolysis, the amount of residual structural strength that will exist in the rock will depend on the original composition and fabric of the strata. Dense marlstone that contains no nahcolite or oil shale will be unaffected by leaching and heating, and so will remain competent for load bearing.

Groundwater Monitoring Program

The Sampling and Analysis Plan For: Environmental Water Quality Monitoring East Research, Development, and Demonstration Lease dated May 2011 will be incorporated into the UIC area permit by reference. The document includes the sampling protocol and analytes to be tested. This document may be revised and updated in the future.

Shell has a established a network of monitoring wells in the 138-4-298 well pad, to monitor groundwater quality and piezometric pressures down-gradient of the RDD Project Site. These groundwater quality monitoring wells collect samples from the Uinta, L7, L6, L5, and L4 hydrostratigraphic WBI units. Shell has collected 4-5 quarters of monitoring data from these wells, and will have collected 5 quarters of monitoring data prior to any injection activities.

Shell has also installed an additional monitoring well, 135-4-298-L4, that is considered a near-field monitoring well to gauge potential impacts from the project prior to their reaching the 138-4-298 well pad that is located further downgradient. The 135-4-298-L4 monitoring well is approximately 60 feet downgradient (northeast) from the RDD Project Site and at least 5 quarters of baseline data will be obtained prior to any injection activities.

PART VII. Additional Wells to Area Permit

Additional new injection wells may be added to the area permit as necessary pursuant to 40 CFR §144.33, provided the Permittee provides notice to the Director. The Director periodically will review the cumulative effects pursuant to 40 CFR §144.33 and advise the Permittee of any required changes to the Permit or mine operations. All sections of the area permit apply to additional well(s) approved for injection. Additional requirements beyond those described in this permit may be required for additional wells that will be included in this area permit.

Shell has submitted a conversion plan for the OB01 and OB03 wells in the event that these wells need to be converted to injections wells to achieve the desired uniform radial dissolution pattern. Any changes to the construction or plugging and abandonment plans must first be approved by the Director and the Permittee shall not begin construction or conversion of the well(s) of the plan until after receiving written authorization from the Director.

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

Plugging and Abandonment Plan

Prior to abandonment, the inert gas used to create the gas cap will be collected at the surface and properly disposed. Additional logs and tests provided in Appendix B will be required. The injection and production tubings will be pulled from the wellbore and a Cement Bond Log or Cement

Evaluation Log will be required for longstring casing to evaluate integrity of cement behind the casing prior to plugging and abandonment.

The wells will be plugged from total depth to surface and any casing leaks will be taken care of when the well is plugged. The well will 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.

Within sixty (60) days after plugging the owner or operator will submit Plugging Record (EPA Form 7520 13) 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 APPENDIX E of the Permit.

PART IX. Financial Responsibility (40 CFR §144.52)

Demonstration of Financial Responsibility
The Permittee is required to maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director. The Permittee will show evidence of such financial responsibility to the Director by the submission of a surety bond, or other adequate assurance such as financial statements or other materials acceptable to the Director. The Regional Administrator may, on a periodic basis, require the holder of a lifetime permit to submit a revised estimate of the resources needed to plug and abandon the well to reflect inflation of such costs, and a revised demonstration of financial responsibility if necessary. Initially, the operator has chosen to demonstrate financial responsibility with:

Standby Trust Agreement

Shell has met financial requirements for the H01 well and two additional wells that may be included in the area permit at a later date.

Evidence of continuing financial responsibility is required to be submitted to the Director annually.