STATEMENT OF BASIS
CLASS IIR PERMIT APPLICATION
RESOLUTE NATURAL RESOURCES COMPANY

U.S. Environmental Protection Agency, Region IX (EPA)
Underground Injection Control (UIC) Permit NN208000001
Aneth Unit H-434 Class IIR Injection Well
San Juan County, Utah
Lease No. 14-20-603-2056
API No. 4303716320

CONTACTS:

Patrick E. Flynn
Resolute Natural Resources Company
1675 Broadway, Suite 1950
Denver, Colorado 80202
Telephone No. (303) 534-4600, ext. 145

James D. Walker
United States Environmental Protection Agency
Ground Water Office
1235 La Plata Highway
Farmington, NM 87401-3901
Telephone (505) 599-6317
Email walker.jim@epa.gov

BACKGROUND INFORMATION

Resolute Natural Resources Company ("Applicant") has applied for a UIC permit to convert and operate a horizontal Class II enhanced recovery well. The vertical portion of the well is located on Navajo Trust land at 700 FSL and 500 FEL of Section 34, Township 40S, Range 24E. The two lateral boreholes are oriented in an east-west direction and are located in the south half of Sections 34, Township 40 South, Range 24 East and the south half of Section 35, Township 40 South, Range 24 East in San Juan County, Utah. The approximate length of each lateral is 2600 feet to the west and 3300 feet to the east. The well is identified as the Aneth Unit H-434 well. The applicant has applied to US EPA Region IX for a UIC permit to allow conversion from oil production to injection of produced water and carbon dioxide (CO_2) into the Paradox Formation at an average injection rate of 350 barrels of water or 800 MCF of CO_2 per day, a maximum injection rate of 3,000 barrels of water or 2,000 MCF of CO_2 per day, and a maximum wellhead injection pressure of 3,000 psig.

Resolute's permit application is administratively complete and EPA has completed its technical review of the application. The EPA has decided to approve this permit, pending public review and comment, and is now issuing a Draft Permit. If approved, the permit will be issued for a period of twenty (20) years, unless the permit is terminated or modified for reasonable cause (40 CFR §§144.39, 144.40, and 144.41). The permit will be reviewed by EPA every five years.

The source of injection fluids will be CO_2 from the McElmo Dome Field, located approximately 25 miles northeast of the H-434 well, and saltwater produced in association with oil and gas production from Paradox Formation oil wells operated by Resolute in the Aneth Unit. The average total dissolved solids (TDS) content of injection fluids is approximately 91,000 ppm based on fluid analyses of water from the Aneth Unit water injection plant. The water will be injected into the Paradox Formation at a depth of approximately 5,400 to 5,684 feet, also containing TDS of approximately 91,000 ppm, based on the analysis of formation water produced from the Paradox Formation in the Aneth Unit oil wells.

The Applicant has notified all interested parties within the Area of Review, which includes the local landowners, land-users, Navajo Nation, Bureau of Land Management, Bureau of Indian Affairs, and the State of Utah.

The Applicant has also requested a permit from Navajo Nation EPA (NNEPA) for conversion and operation of this Class IIR injection well. Issuance of this NNEPA draft permit is currently under review by NNEPA and is pending completion of the technical review of the application.

This Statement of Basis describes the specific permit conditions and the basis for those conditions under authority of the Underground Injection Control (UIC) regulations and the UIC provisions of the Safe Drinking Water Act.

BRIEF SUMMARY OF PART II. SPECIFIC PERMIT CONDITIONS

SECTION A. WELL CONSTRUCTION

1. Casing and Cementing

The vertical wellbore was drilled and completed in July 1958 as and oil well in the Desert Creek Member of the Paradox Formation. The well was recompleted as an oil well in December 1965 in the Ismay and Desert Creek Members of the Paradox Formation. The well was re-entered by Resolute in 2007 to drill the two open-hole lateral extensions and resume oil production from the Paradox Formation. The uppermost casing window is at 5,400 feet and the lateral boreholes penetrate the lower Honaker Trail Formation and Ismay member of the Paradox Formation before entering the Desert Creek Member of the Paradox Formation in a horizontal orientation. The wellbore schematic diagram can be seen in Appendix C of the permit.

The well is cased and cemented to prevent the movement of fluids into an underground source of drinking water (USDW). The surface casing is 13-3/8 inches in diameter, set at 37 feet and cemented to the surface with 75 sacks of cement. The intermediate casing is 9-5/8 inches in diameter, set at 1,598 feet and cemented to surface with 1000 sacks of 50-50 Pozmix cement. The long string casing is 5-1/2 inches in diameter, set at 5,702 feet and cemented with 500 sacks of cement from 5,702 feet (TD) to 3897 feet, as reported by the applicant. Injection tubing will be 3 inches in diameter, set with an injection packer assembly at 5,326 feet of depth.

The injection zone is overlain by 700 feet of tight carbonates and fine-grained siliciclastics in the Honaker Trail formation and approximately 3,000 feet of shales, siltstones, and saline aquifers in the Permian section, providing multiple confining layers to the injection zone at 5400 feet. The USDWs above 1,594 feet are protected from the inflow of fluids by surface, intermediate, and long string casing and adequate cement placement in the annulus of all casing strings. The tubing/packer assembly also provides another layer of protection from inflow of injected fluids into the USDWs.

2. Formation Logging and Testing

The static fluid level and/or injection zone pressure must be measured and reported to the EPA on an annual basis. A step-rate injectivity test may be required for the determination of formation fracture pressure if the applicant seeks to exceed the maximum allowable injection pressure during the life of the well.

3. Monitoring Devices

The Applicant is required to install pressure gauges or FIP (female) fittings with cut-off valves to allow an inspector to obtain injection pressure measurements. A flowmeter shall be installed for measuring flow rates and cumulative volumes injected and a sampling tap shall be installed on the injection pump discharge line for the purpose of periodically obtaining representative samples of the injection fluid. Casing and tubing pressures will be monitored at the surface on a weekly basis by means of pressure/vacuum gauges.

SECTION B. CORRECTIVE ACTION

An oblong Area of Review (AOR), approximately 1,218 acres in size as measured from the lateral position of the two horizontal boreholes, has been proposed by the Applicant. The boundary of the AOR is defined by a distance of one-half mile from the two laterals in all directions. The applicant reports that there are 13 well penetrations of the Paradox Formation within the AOR of the subject well. The permit will be issued based on corrective action considerations associated with the proposed AOR. Corrective actions are not required as condition of injection operations since all of the wells within the AOR are constructed or plugged and abandoned to prevent movement of injection fluids into USDWs. However, any wellbores that lack sufficient intermediate string casing and cement in the long string annulus to isolate the Navajo Aquifer (lowermost USDW) from potential interformational fluid flow will require remedial cementing when casing leaks are detected or when the well is plugged and abandoned. One well (Aneth Unit G-334) in the AOR has known deficiencies in the casing and cement placement and will require remedial cementing if a casing leak is detected during operations or mechanical integrity testing. If casing leaks do not occur, remedial cementing will be required when the well is plugged and abandoned.

SECTION C. WELL OPERATION

1. Mechanical Integrity

A mechanical integrity test (MIT) of the casing, tubing, and packer will be conducted prior to commencement of injection operations in the well. The purpose of this test is to ensure there are no significant leaks in the tubing, packer, and casing. The standard MIT procedure requires applying a pressure at least equal to the maximum allowable injection pressure in the tubing/casing annulus for thirty (30) minutes with no more than 5% change in pressure. A differential of at least three hundred (300) psig between the tubing and tubing/casing annulus will be maintained throughout the test. Demonstrations of mechanical integrity of the injection tubing and casing will be required every five (5) years and within thirty (30) days after any workovers or alterations of the wellbore, prior to resuming injection. An alternative to the standard MIT is to apply a pressure of at least 1,000 psig and perform the MIT every three (3) years, which is the operator's preferred alternative for injection wells in the Greater Aneth Field.

2. Injection Interval

Injection will be permitted for the Lower Honaker Trail and Paradox Formations in the subsurface interval at approximately 5,400 to 5,684 feet. The Desert Creek member of the Paradox Formation is expected to take most, if not all of the injected fluids, since the horizontal boreholes are contained within the Desert Creek zone. Any proposed change of injection formation or enlargement of this interval would require a permit modification, subject to public notice, comment and appeal.

3. Injection Pressure Limitation(s)

The wellhead injection pressure shall not exceed the maximum allowable injection pressure, calculated by multiplying the actual depth to the top of the injection interval by a fracture gradient of 1.0 psi/foot, less the hydrostatic pressure of the injection fluid. The average fracture gradient of the Paradox Formation is known to exceed 1.0 psi/ft, but is not as high as the 1.3 psi/ft value claimed by the applicant, based on numerous step-rate tests conducted in

Greater Aneth Field wells. The maximum injection pressure may be increased only if a valid step-rate test is conducted by the operator and is witnessed and approved by the EPA. Injection pressure shall not exceed the fracture pressure of the injection zone as determined by the EPA from the analysis of step-rate test results. **The initial maximum allowable injection pressure is set at 2900 psig**, based on a depth of 5400 feet to the top of the injection interval and a hydrostatic pressure of 2490 psig (0.461 psi/ft. gradient) at that depth.

4. Injection Volume Limitation:

The proposed average injection rate is 350 barrels of water per day and 800 MCF of CO_2 per day and the proposed maximum injection rate is 3,000 barrels of water per day and 2,000 MCF of CO_2 per day. The cumulative volume of water and CO_2 that would be injected into the injection zone, assuming the average injection rates are applied over the 20-year term of the permit, equals 2.6 million barrels. The storage capacity of the injection zone within the proposed area of review (AOR) is an estimated at 38.1 million barrels, based on injection zone formation properties and thickness determined from wireline log analysis. The proposed AOR is oblong in shape and is defined by a boundary that is a distance of one-half (½) mile from the lateral position of the two horizontal boreholes, which are approximately 2,600 and 3,300 feet in length. The above calculations are based on the following assumptions and formation properties: a homogeneous injection zone, average effective porosity of 11.8 %, residual water and gas saturation of 40 %, and net thickness of 57 feet. The storage capacity of the reservoir is not an important consideration in EOR operations such as this one; however, since the volumes of formation fluids that will be withdrawn are similar, if not equivalent, to the volume of produced water and CO_2 that will be injected into the reservoir over the 20-year term of the permit. Injection fluids will therefore be contained or withdrawn from production wells within the AOR.

The potential for migration of formation fluids out of the injection zone and into USDWs will be quite low because reservoir pressure build-up will be limited by withdrawals of formation fluids from production wells. Furthermore, all wellbores that penetrate the injection zone within the AOR are cased and cemented to prevent migration of injected fluids into USDWs. In addition, there are no known faults or fractures that would allow migration of fluids into USDWs within the proposed AOR. Endangerment of USDWs due to pressure build-up and migration of injected and formation fluids is therefore highly unlikely. Formation pressure in the injection zone will be monitored annually during the term of the permit, and corrective actions will be taken if pressure build-up may endanger USDWs. The injection rate and volume will be limited only to the extent that the maximum allowable injection pressure is not exceeded and reservoir pressure does not increase to a level that could cause movement of fluids into USDWs in wellbores within the AOR.

SECTION D - MONITORING, RECORD KEEPING, AND REPORTING OF RESULTS

The Applicant is required to sample and analyze the water quality of the injected fluids at annual intervals and whenever the source of the injection fluid changes. Water samples shall be analyzed for TDS, major ions, pH, specific conductivity, specific gravity, and viscosity. Measurements of the injection pressure, annulus pressure, injection rate, and cumulative volume must be observed weekly and recorded at least once per month. The Applicant is required to submit an Annual Monitoring Report to the EPA summarizing the monitoring of injection rates, volumes, pressures, and injected fluid, and any major changes in the characteristics or sources of injected fluid. Static fluid levels and/or pressures will be measured and will be reported to the EPA on an annual basis.

SECTION E - PLUGGING AND ABANDONMENT

The EPA has reviewed the plugging and abandonment (P&A) plan submitted by the applicant. The P&A plan is incorporated into the permit as Appendix A. **The current estimated cost of plugging and abandoning the well must be provided and approved prior to issuance of the final permit**, and will be reviewed periodically to ensure that the P&A cost estimate remains current and accurate. The plugging plan and procedure will be reviewed prior to commencement of plugging operations to ensure that the well is abandoned in a manner that protects USDWs.

SECTION F - FINANCIAL RESPONSIBILITY

The Applicant must furnish an acceptable financial instrument prior to issuance of the final permit, sufficient to guarantee current costs of plugging and abandoning the subject well in the event the Applicant fails to properly plug and abandon the well, whenever that may become necessary. The EPA is the specified beneficiary of the aforementioned surety instruments. The EPA will review and may require updating of the financial responsibility mechanism periodically as plugging and abandonment costs increase, or as other circumstances may require.